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ENERGY TAX PROVISIONS

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TAX ON BUSINESS USE OF OIL AND NATURAL GAS, USERS TAX REBATES AND BUSINESS ENERGY TAX CREDITS

PREPARED FOR THE

COMMITTEE ON FINANCE
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BY THE STAFF OF THE

JOINT COMMITTEE ON TAXATION

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INTRODUCTION

This pamphlet is the fifth in a series prepared for the use of the Committee on Finance during its consideration of tax provisions of the House-passed energy bill (title II of H.R. 8444). This pamphlet deals with three topics: the proposed tax on business use of oil and natural gas, the users tax rebates, and the business energy tax credits.

This pamphlet contains a background section which outlines certain facts concerning the energy and economic situation in this area. There follows a discussion of each of the major topics, and each of these topics is divided into subparts. First there is a section on present law. Next there is a discussion of the provisions of the House-passsed bill, followed by the Administration's position on those provisions. There follows a discussion of other Congressional consideration of the subject matter, including consideration by the Senate Finance Committee in the 94th Congress and consideration of related topics by other Senate committees and by the Senate in the 95th Congress. Finally, there is a discussion of possible areas for committee consideration.

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I. BACKGROUND

A. Business Consumption of Oil and Natural Gas

Natural Gas

Consumption

Natural gas which comes from the well is "wet", which means that it contains both "dry" natural gas (i.e., the substance commonly thought of as natural gas) and natural gas liquids. This "wet" gas is processed by natural gas processing plants, which separate the wet gas into dry gas and natural gas liquids. Some natural gas liquids are further processed by petroleum refineries. Natural gas liquids are considered "petroleum products" (discussed in the next section).

Between 1950 and 1970, total consumption of "dry" gas grew at an extraordinarily rapid rate; it peaked in 1972 and has declined since then. Total natural gas resources are estimated to be approximately equal to 45 years worth of 1975 consumption. Proved reserves of natural gas (i.e., those known reserves which can be economically extracted with existing technology at existing price levels), however, have declined sharply from 291 trillion cubic feet in 1970 to 216 trillion cubic feet in 1976.

Because companies will construct pipelines only if they are assured of gas supplies for many years, most natural gas is sold under long-term contracts which require producers to dedicate certain reserves to particular pipelines or to particular consumers. Many of these contracts fix the price of gas well below the world market price for other sources of fuel. As a result, gas producers have been depleting existing gas reserves at a very rapid rate in an attempt to satisfy current demands of gas consumers, but gas producers have been unwilling to develop new reserves and commit such reserves to long-term contracts, presumably in the expectation that gas prices will rise still further.

The result has been natural gas shortages which have resulted in curtailments of gas supplies to certain users. These were particularly severe in the cold winter in 1976–77, when gas shortages required layoffs in many industries.

TABLE 1.—*Domestic consumption of petroleum products and natural gas, by major product and major consuming sector, 1976 (estimated)*

[Quadrillion Btu]

	Household and commercial	Industrial	Transportation[1]	Electricity generation, utilities	Total domestic product demand[2]
Petroleum products:[3]					
Fuel and power:					
Liquefied gases[4]	0.682	[5] 0.281	0.108		1.071
Jet fuels			2.007	0.017	2.024
Gasoline			13.440		13.440
Kerosene	.269	.078			.347
Distillate fuel	3.144	.814	2.216	.419	6.630
Residual fuel	1.169	1.232	.798	3.043	6.279
Still gas		1.092			1.092
Petroleum coke		.386			.385
Total	5.264	3.883	18.569	3.479	31.268
Raw material:[6]					
Plant condensate		.019			.019
Special naphthas		.157			.157
Lubes and waxes		.221	.164		.384
Petroleum coke		.157			.157
Asphalt and road oil	1.068				1.068

Petrochemical feedstock offtake:					
Liquefied refinery gas [7]		.160			.160
Liquefied petroleum gas [7] [8]		.720			.720
Naphtha		.402			.402
Still gas		.099			.099
Miscellaneous		.350			.350
Total	1.068	2.283	.164		3.515
Miscellaneous and unaccounted for					.155
Grand total, petroleum products	6.333	6.166	18.733	3.479	34.938
Natural gas: [9]					
Fuels and power	[10] 8, 117	[11] 7.755	[12] .582	3.134	19.588
Raw materials (chemical)		.628			.628
Grand total, natural gas	8.117	8.483	.582	3.134	20.216
Total petroleum and natural gas consumption	14.450	14.649	19.315	6.613	55.153

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[1] Includes bunkers, military transportation, and all military use of distillate and residual fuel oils.

[2] Includes miscellaneous and unaccounted for users, not shown separately.

[3] Includes liquefied refinery gas and natural gas liquids.

[4] Includes liquefied refinery gases (made from petroleum) and liquefied petroleum gases (made from natural gas). Examples are propane and butane.

[5] Includes secondary recovery of petroleum and agriculture uses.

[6] Includes some fuel and power used by raw materials industries.

[7] Includes ethane.

[8] Includes liquified petroleum gas for synthetic rubber.

[9] Does not include use of 2.4 quads for production of liquefied petroleum gases.

[10] Includes 0.247 quads delivered to municipalies and public authorities for heating, etc.

[11] Includes approximately 1.4 quads used as fuel in gasfields and natural gas processing plants.

[12] Consists of fuel used by natural gas pipelines.

Source: Bureau of Mines.

TABLE 2.—*Industrial energy consumption, 1974*

[In trillion Btu's]

Industry group	Coal	Oil [1]	Natural gas	Electricity	Other	Total
Manufacturing	3, 642. 0	4, 420. 2	8, 109. 1	2, 092. 0	1, 842. 9	20, 106. 2
Food and kindred products	75. 3	132. 3	475. 6	126. 7	124. 8	934. 7
Tobacco products	5. 5	5. 2	4. 5	3. 5	. 3	19. 0
Textile mill products	22. 0	62. 7	102. 1	91. 8	38. 1	316. 7
Apparel	1. 0	5. 7	15. 4	25. 0	17. 9	64. 0
Lumber and wood	2. 8	42. 4	72. 9	50. 5	84. 7	253. 3
Furniture and fixtures	2. 8	7. 6	25. 3	14. 2	9. 1	59. 0
Paper and allied products	208. 8	576. 4	414. 3	132. 7	891. 6	2, 223. 8
Printing and publishing	. 4	7. 2	31. 4	31. 5	18. 2	88. 7
Chemicals	322. 2	2, 085. 4	2, 092. 6	436. 9	274. 0	5, 211. 0
Petroleum	5. 3	745. 3	2, 154. 5	83. 7	83. 2	3, 072. 0
Rubber	29. 6	44. 0	86. 6	64. 7	26. 0	250. 9
Leather	1. 3	6. 3	5. 2	5. 5	3. 5	21. 8
Stone, clay, and glass	233. 0	125. 5	696. 3	99. 6	146. 9	1, 301. 3

See footnote at end of table.

Table 2.—*Industrial energy consumption, 1974*—Continued

[In trillion Btu's]

Industry group	Coal	Oil [1]	Natural gas	Electricity	Other	Total
Primary metals	2, 639. 2	418. 7	1, 284. 3	536. 3	[2] (76. 1)	4, 802. 4
Fabricated metal products	11. 1	38. 9	208. 2	88. 4	60. 7	407. 3
Machinery	20. 1	33. 5	164. 3	90. 7	52. 5	361. 1
Electrical equipment	13. 2	21. 4	96. 9	84. 2	31. 0	246. 7
Transportation equipment	47. 6	40. 5	144. 1	97. 1	41. 1	370. 4
Instruments		12. 7	15. 8	15. 6	6. 4	50. 5
Miscellaneous manufacturing	. 8	8. 5	18. 8	13. 4	9. 0	50. 5
Agriculture	. 8	1, 129. 2	167. 6	109. 2		1, 406. 8
Mining	39. 4	265. 2	1, 369. 0	142. 1	123. 4	1, 930. 1
Construction		1, 830. 5		15. 3	9. 3	1, 855. 1
Electric utilities	8, 562. 8	3, 275. 8	3, 463. 7	[3] (6, 363. 3)	2, 248. 7	11, 187. 7
Total	12, 245. 0	10, 911. 9	13, 109. 4	[3] (4, 004. 7)	4, 224. 3	36, 485. 9

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[1] Includes liquefied petroleum gas (LPG).

[2] Steel industry produces coke, regarded as a fuel.

[3] Figures in parentheses mean energy produced in excess of needs for consumption.

Source: Federal Energy Administration.

The 1976 consumption of dry natural gas is shown at the bottom of table 1. Residential and commercial customers (who would generally not be subject to tax under the House bill) accounted for 40 percent of total consumption.

Electric utilities used 15 percent of the natural gas and industrial users consumed 42 percent. (This industrial figure includes 7 percent used as fuel by natural gas processing plants and in gas fields.) The remaining 3 percent was used in natural gas transportation as pipeline fuel.

Natural gas is used primarily as a fuel, but it also has some important subsidiary industrial uses as feedstocks and in irrigation pumping. In 1976, about 3 percent of total consumption was used as feedstocks in the chemical industry, principally for the production of fertilizers and plastics.

In industry, about 40 percent of the natural gas used as fuel is for boilers. The remainder is used in other types of combustors, such as kilns and furnaces.

A tax aimed at industrial and utility users would affect about 44 percent of natural gas consumption. (This would exclude use as petrochemical feedstocks, and use as fuel in gas fields, natural gas processing plants, and in pipeline transportation.) The vast majority of this gas is used by the utilities and the approximately 1400 large industrial firms which are subject to tax under the House bill. (Small users would not be subject to the tax because of the 50,000 barrel exemption.)

Users who could potentially convert to coal, however, account for less than 45 percent of consumption, because some industries use gas for process heating (for which use of coal is often impractical) and in boilers too small or too new to make conversion economical in the foreseeable future. As shown in table 2, the principal industries which would be affected by such a tax are chemicals, petroleum refining, and primary metals (although the impact on specific industries would be reduced by the various exemptions in the House bill).

About one-third of utility gas consumption and about one-quarter of industrial consumption is under "interruptible" contracts, which allow the distribution company to terminate service at times of heavy demand and short supply. Interruptible users normally convert to fuel oil when their natural gas supply is cut off. Generally interruptible customers pay less for their gas than those having firm contracts; the size of the discount varies by area. The advantage to the distributor is that interruptible customers can use gas on a year round basis (whereas residential customers, for example, generally use little or no gas during warm weather periods). This arrangement keeps the pipeline operating at reasonably full capacity throughout the year.

Effect of pricing policies

The price of natural gas sold in interstate commerce is regulated by the Federal Power Commission (FPC). In mid-1976, the average wellhead price of natural gas sold to major interstate pipelines was 44 cents per thousand cubic feet (mcf). These pipelines purchased about one-half of the gas produced in the United States. The price ceiling for interstate natural gas is now $1.45 per mcf, but the average price at which interstate gas is sold is considerably less than this because many prices are set by old long-term contracts.

The price of gas sold within the producing States is considerably higher than $1.45, and in some cases exceeds $2.00, so that producers are dedicating relatively little new gas to interstate commerce. The principal exception is offshore gas, which is subject to FPC regulation no matter where it is sold.

The distortions resulting from the existing methods of pricing natural gas can be seen by comparing gas and oil prices. Comparisons between different energy sources can most easily be made in terms of Btus, or British thermal units. A Btu is the amount of energy required to raise the temperature of one pound of water by one degree Fahrenheit. A barrel of crude oil, the equivalent of 42 gallons, contains, on the average, about 5.8 million Btus. (The Btu content of oil varies from barrel to barrel, however, depending on the quality of the oil.) Natural gas contains about 1 million Btu per thousand cubic feet, or mcf. Coal contains about 23 million Btu per short ton.

In April 1977, the average price of gas sold to residences was $2.27 per mcf. Since one barrel of distillate fuel oil contains 5.7 times as much energy as one mcf of gas, this natural gas price is equivalent to a price of $12.94 per barrel for distillate fuel oil. That same month, the price of heating oil was $19.28 per barrel, so that residential gas prices were only two-thirds of heating oil prices and incentives for gas conservation were correspondingly weaker.

In November 1976, the price of gas sold by the major interstate pipelines to industrial users averaged $1.07 per mcf, which is equivalent to a price of $6.16 per barrel for residual fuel oil, but residual fuel oil itself sold for an average price of $11.61 per barrel. Thus, those companies lucky enough to be customers of an interstate pipeline incurred only about half the energy cost of their competitors who must rely on fuel oil.

Future production of natural gas from conventional sources is not likely to increase significantly above current levels if prices remain in the vicinty of their present levels. Many analysts believe that if serious technological and environmental problems could be overcome and prices were to reach approximately $5 per mcf (after adjusting for inflation), approximately double the current world oil price equivalent, then substantial supplies of gas might become available from such sources as synthetic natural gas, coal seam methane, Devonian shale, and geopressurized gas.

Petroleum Products

Consumption

Petroleum products are derived from crude petroleum and from natural gas liquids. Petroleum products used in industry consist primarily of distillate and residual oil. Natural gas liquids include natural gasoline, propane, butane and ethane. Natural gas liquids supply about 10 percent of the U.S. demand for refined petroluem products.

As shown in table 1, a tax on industrial and utility use of petroleum products would not affect the majority of petroleum products. Approximately 54 percent of these products are used for transportation (commercial, governmental, and individual).

Household and commercial users account for 18 percent. These users rely primarily on residual and distillate fuel oils, liquefied gases, and kerosene for heating purposes. Asphalt and road oil are also allocated to this sector.

Industrial and electrical utilities users account for 28 percent of petroleum products use. This is divided into 21 percent for fuel uses, 5 percent for petrochemical feedstock uses, and 2 percent for other raw material uses. Approximately 40 percent of industrial use of petroleum products for fuel is for boilers; the remainder is for other types of combustors.

Under the House bill, products used as raw materials would be exempted from the tax. Thus, under the House bill, about 21 percent of total consumption of petroleum products could be taxed by an industrial and utility users tax. As shown in table 2, the chemical and petroleum refining industries would be the largest payers of the tax. (However, this table does not take into account the House bill's exemptions for feedstocks and certain process uses.)

Prices for the natural gas liquids other than ethane and for gasoline are currently subject to controls, although the Administration proposes to remove gasoline prices from controls later in 1977.

Imports

Petroleum is the most significant single energy source in the United States. In 1976, it accounted for 47 percent of U.S. energy consumption and for more than 95 percent of energy consumed in transportation. The total amount of oil consumed in the United States doubled between 1950 and 1970; except for a slight decline during the 1974 recession, U.S. oil consumption has continued to rise.

Domestic oil production has declined steadily since 1970 when production of crude oil and natural gas liquids peaked at approximately 4.1 billion barrels.[1] By 1976, domestic production declined to approximately 3.5 billion barrels.

The inevitable result of rapidly increasing oil consumption and declining domestic production has been a significant growth in oil imports. Until 1965, the United States was self-sufficient in oil because its spare (unused) production capacity for crude petroleum exceeded its oil imports. However, since 1972, domestic production has proceeded at full capacity and imports have risen steadily. In 1976, oil imports amounted to 7.3 million barrels per day (mbd), or 2.7 billion barrels per year, which is 42 percent of consumption.

The United States imports oil principally from Venezuela, Arab countries, Canada, Iran, and Indonesia. In 1975, the United States was dependent on Arab suppliers for 30 percent of its imports and 11 percent of its consumption. In 1976, this dependence on Arab suppliers increased to 38 percent of U.S. imports and 15.9 percent of U.S. consumption.

Without any change in current policies, there is likely to be a significant increase in our dependence on imported oil in future years. The Federal Energy Administration estimates that under current energy policies, oil imports will be 48 percent of consumption in 1980, 50 percent of consumption in 1985, and 58 percent of consumption in

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[1] Estimate of production of crude petroleum includes natural gas liquids.

1990. These FEA estimates are consistent with independent private forecasts.

Moreover, many U.S. allies, including Japan, Germany, France, and the United Kingdom, have relied on imports for more than 95 percent of their oil needs in recent years. These countries have relied on Arab suppliers for one-half to three-quarters of their total oil consumption. Except for the United Kingdom, which may become self-sufficient for a period of time as a result of North Sea oil production, these countries will continue to rely heavily on imports in the future.

B. Alternate Fuel Sources

Coal

One likely effect of a tax on utility and industrial use of petroleum products and natural gas would be to increase the use of coal.

Coal is the most abundant fossil fuel available in the United States. The known reserves are sufficient to meet domestic needs for several centuries. This abundance is especially important now in view of the prospect for substantial price increases for petroleum, natural gas and their products and the prospect that proved oil and gas reserves will not keep pace with future oil and gas consumption. Coal is most important immediately because of its suitability as a fuel substitute for oil and gas and because coal is potentially a source for synthetic oil and gas. Its drawbacks are its adverse environmental impact and the relatively high cost of its extraction, transportation and use.

Coal reserves

Domestic coal reserves are approximately 437 billion tons and are found in 30 States. Slightly more than half the reserves, 234 billion tons or 54 percent, are located in western states. About two-thirds of the total is found in 5 states—Montana, Illinois, Wyoming, West Virginia and Pennsylvania, in order of size of reserve.

About 46 percent, or 200 billion tons, has a sulfur content below 1 percent, which is below the level deemed satisfactory to avoid air pollution. Almost all of the coal reserves in Montana and 60 percent of those in Wyoming are in this category. Almost the same amount of coal reserves, 186 billion tons, has a high sulfur content.

About 300 billion tons, or 69 percent of all coal reserves, can only be recovered through relatively high cost underground mining techniques; the remainder may be recovered by surface mining.

Production, consumption, and transportation

Domestic production of coal in 1977 is estimated at 700 million tons, an increase of more than 5 percent over 1976 production. Production has increased by 155 million tons, or 28 percent, since 1968, with two-thirds of the increased production levels occurring after 1973. Electric utilities have long been the major consumer of coal, and during this period since 1968, their share of coal consumption increased from 54 to 68 percent. The increased share reflects increased generation of electrical energy and some shifts from use of oil and natural gas to coal as boiler fuel.

Coal production generally is described as being demand limited, that is, the level of production is determined by the demand for it, as illustrated by the increases in production and consumption since

1968. Consumers of large amounts of coal, primarily electric utilities and some industrial firms, tend to sign contracts directly with mine owners for all or a specific portion of the mine's output. Financing is readily available once these contracts are signed. Several years of lead-time are necessary between the decision to open a mine and the start of production. The interval between the decision to open a new coal mine and shipment of the initial load of consumable coal usually is long enough to provide for transportation of the coal, including the manufacture of additional carriers needed, and construction of new railroad roadbeds.

Coal is transported from the mine to the consumer primarily by train. In 1974, railroads carried 66 percent of the coal that moved between mines and consumers. Water transportation and trucks, respectively, carried 11 percent of the total. The rest was carried in miscellaneous forms, including a small amount by slurry pipelines.

The existing railroad lines may be extensive enough to carry the coal where it is needed. If they are not and new railroad lines must be put in place, this could cause some delay in the delivery of coal by rail to those areas where it is needed. Flexibility exists with respect to freight cars, because more efficient use of the cars, especially shorter turn-around time, could offset a temporary shortage in the number of cars. The condition of roadbeds in some sections in the country is being corrected under a program which was begun in April 1977 under the Railroad Revitalization and Regulatory Reform Act of 1976.

Coal slurry pipelines can move coal efficiently between fixed terminals over a fixed route. The pipeline moves a water and coal mixture, and by its nature places relatively large, additional demand on the water supply in the area where the coal is mined. Problems with the use of slurry pipelines may arise in those areas where there is not a copious flow of water. The pipelines require substantial initial capital costs, but the operating costs are relatively low. Currently construction of the pipelines has been delayed because legal complications have arisen over the rights-of-way.

Expansion of mining capacity

The proposed national energy program, as presented by the Administration, calls for continued, substantial increases in coal consumption by industry and electric utilities that will result from continuation of the pattern that began after 1973—a substantial shift from oil and natural gas to coal, nuclear fuel or other sources. In part, the ability of the coal industry to provide sufficient output is demonstrated by the production increases in the past several years. Even more rapid increases may be necessary in the future as the electric utility industry is shifted from reliance on oil and gas.

As indicated above, coal production in 1977 is estimated to be 700 million tons, an increase of 35 million tons (or 5 percent) over 1976. Projections made in 1976 as a result of surveys by the National Coal Association and FEA indicate current plans to expand coal production capacity over 1976 levels by about two-thirds by 1985. These expansion plans were developed on the assumption that difficulties (if any) with the size of the available labor force and transportation systems would not seriously restrict deliveries of coal to consumers.

Coal prices and profit

Coal prices, per million Btu, are approximately 50 percent below the equivalent oil price and 10 to 20 percent above the equivalent gas price. Coal prices are unregulated and basically responsive to the demand for coal.

Electric utilities, the dominant consumers of coal, tend to sign long-term contracts for a mine's total output. The contract price usually reflects the current market price when the contract is signed, with provisions for a pass-through of higher operating costs and occasionally some protection of profit margins. Spot prices of coal, the type used primarily as boiler fuel, ranged between $10 and $20 a ton in mid-1976 and have risen since then. A rising trend should continue through 1977 as consumers build inventories as a hedge against a coal strike late in 1977. Subsequent prices could be affected strongly by prices of oil and gas, including any new oil and gas taxes, which consumers will be paying.

Ownership of coal

Generally, domestic coal mines are owned by corporations primarily involved in other economic activities. There is only one coal company (North American Coal) among the 10 largest steam coal producers in 1975; two of the 10 were electric utility systems (American Electric Power and Pacific Power and Light).

Among the 150 largest holders of coal reserves, seventy of the companies are primarily coal producers, but 44 of them produced nothing or less than 100,000 tons in 1975. Oil and gas companies and electric utilities were the next two largest types of holders of coal reserves. Thirty-nine of the companies produced 2 million or more tons; 8 were coal companies, 9 were in oil and gas, and 6 in each of electric utilities and steel. The 9 oil and gas companies held the largest reserves—28 billion tons; the 8 coal companies and 3 companies in metals other than steel each held reserves of 10 billion tons, and electric utility and steel companies held between 5 and 6 million tons each.

Technical feasibility of coal conversion

Conversion to coal involves a shift by the industrial and electric generating sectors from oil and gas. Currently, they use about 21 quadrillion BTU's of energy annually. Coal cannot, however, replace oil and gas for all industrial uses. The primary industrial area in which conversion to coal is feasible is the generation of process steam which essentially involves using coal fired steam boilers instead of gas or oil fired boilers. This conversion generally cannot be achieved by refitting a gas or oil boiler so that it can use coal, unless the boiler was originally a coal boiler which was converted to gas or oil.

It is estimated that in 1977 dollars, it costs about $575 million to build a 1,000-megawatt coal-fired electric generating plant, including the scrubbers necessary to remove sulfur from the exhaust gases. This comes to a cost of about $575 per kilowatt. A 1,000-megawatt plant is adequate to meet the energy needs of a city of approximately 1 million people.

There is, however, considerable regional variation in these construction costs. For example, the cost of construction in the Southeast is about 9 percent below the national average and the cost in New England is about 11 percent above the national average.

In the case of a public utility, it takes approximately 8 years to site and construct a coal-fueled facility. However, somewhat shorter conversion times, ranging from perhaps 2 to 3 years, are possible in the case of industrial conversion to the use of coal.

Nuclear Energy

Since the 1950's, the United States has encouraged the use of nuclear energy as a long-term replacement for fossil fuels to generate electricity. Through the Atomic Energy Commission and its successors, the Nuclear Regulatory Commission and ERDA, research and development on nuclear power has continued for 25 years. The United States is now in its 18th year of commercial nuclear power production.

In the current nuclear power plant, the nuclear fuel core replaces fossil fuel in the generation of steam which in turn drives turbines which generate electricity. A nuclear fuel core contains uranium fuel which has been enriched in its fissionable Uranium–235 (U–235)[2] content. When U–235 is bombarded by neutrons, the uranium atoms split ("fission") and release energy in the form of heat plus additional neutrons which sustain the nuclear reaction. The heat is transferred to the primary coolant, which can be boiling water, pressurized subcooled water, gas or liquid metal. This heated substone is used to produce steam, which turns a turbine generator which in turn produces electricity.

Types of reactors

There are three main types of reactors in use or being funded in the United States: (1) light water reactors, (2) gas cooled reactors, and (3) the developing liquid-metal fast breeder reactors.

(1) *Light water reactors.*—Light water reactors are fueled by enriched uranium dioxide (UO_2). Their name derives from the fact that ordinary water is used to cool the core, and in so doing generates steam which drives a turbine generator. The water may be either boiling or pressurized in its uses as a coolant.

(2) *Gas cooled reactors.*—Gas cooled reactors are fueled by U–233 in the initial reactor core and thorium–232, which is converted to uranium–233, in subsequent cores. High pressure helium gas is used as the coolant. Because of the high pressure and temperature steam provided by these reactors, the gas cooled reactor has a net thermal operating efficiency of nearly 40 percent. There is only one such reactor in the United States.

(3) *Liquid metal fast breeder reactor.*—This type of reactor produces more nuclear fuel than it consumes. A fast breeder reactor converts nonfissionable (and abundant) U–238 to fissionable plutonium–239. For the past 20 years, the government has been conducting research and development on the breeder concept.

Use of nuclear fuel in electricity generation

The importance of nuclear power for domestic electricity supply has grown markedly in the past several years. In 1973, nuclear-fueled electricity constituted 4.5 percent of domestic electricity supply. In 1974, it rose to 6 percent; in 1975 it averaged 9.0 percent, and it averaged 9.3 percent in 1976. In January 1977, a period of unusually cold weather and high electricity demand, nuclear power plants generated 11.3 percent of all U.S. electricity.

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[2] The term U–235 means uranium with an atomic weight of 235. The number 235 refers to the number of neutrons and protons in the atom.

In the past 4 years, concern over growth in electrical demand, waste disposal, safety, reprocessing, capital costs, and uncertainties over the price and availability of uranium have led utilities to delay their orders for new reactors. In 1973, 34 reactors were ordered, in 1974, 26 reactors were ordered, in 1975, 4 reactors were ordered, and in 1976, 1 reactor was ordered.

Operational safety

While many have serious concerns about the possibility of a nuclear accident, the operational safety record of nuclear plants in the United States thus far has been excellent. According to information supplied by the U.S. Nuclear Regulatory Commission, through May 31, 1977, U.S. nuclear plants have produced 326 reactor years of operation without any radiation accident resulting in a known death among plant personnel or among the general public.

In 1968, the former Atomic Energy Commission (AEC) adopted a plan for the collection of radiation exposure records for persons working with radioactive materials or in radioactive environments. For the period 1968–1975, only 22 out of a more than 400,000 recorded annual exposures exceeded those permitted under Federal safety regulations, under carefully monitored circumstances. There has been only one such instance during each of the last three years.

Plutonium

Plutonium is a byproduct of both the light water reactor and the liquid metal breeder reactor. Because plutonium is used to make nuclear weapons (30 pounds of plutonium—about half the annual byproduct of a current light water reactor—is sufficient to make a substantial nuclear weapon), there is serious concern that the security of the nuclear fuel cycle be maintained. Because the liquid metal breeder reactor generates more plutonium than it consumes, the use of this technology, as compared to conventional light water reactor technology, substantially compounds the security problem. In April of this year, the Administration reversed previous policy and proposed to stop commercialization of the Clinch River breeder but proposed to continue work on research and development of non-plutonium breeder reactors.

Waste management

Any nuclear technology creates radiation hazards and problems of waste management. Because radioactive decay is extremely slow, such materials must be stored for long periods of time. While a variety of technologies are available to do this, many, such as underground storage, require continuous surveillance, since there is a constant risk of ground water contamination. To a large extent, public criticism of nuclear power has shifted from reactor safety to radioactive waste.

Currently, ERDA is conducting field investigations and analyses in 36 States to determine the suitability of underground structures for waste disposal. The Environmental Protection Agency and Council on Environmental Quality have repeatedly expressed concern about waste management problems. The President has directed that a review be made of the waste management program.

Availability of uranium

The recent quadrupling in the price of yellowcake (the trade name for uranium ore, needed in the production of reactor fuel) coupled with an Administration decision to defer commercialization of the liquid metal breeder reactor (which is capable of producing nuclear fuel) means that there will be higher prices for uranium.

Estimates of U.S. uranium reserves vary considerably. Table 3 contains July, 1976, ERDA estimates of domestic uranium oxide reserves. The forward cost represents the cost of producing additional yellowcake with existing facilities. An average thousand megawatt reactor uses 6,000 tons of yellowcake over its 30-year life, or 200 tons a year. Current total annual reactor consumption is 17,200 tons a year. Known reserves represent 17 years supply of yellowcake at estimated 1987 consumption rates. If probable reserves are added to known reserves at the $30 forward cost, there are 41 years of supply. These supply figures, of course, assume a constant consumption level.

TABLE 3.—*Reserves of uranium oxide (yellowcake)*

[In thousands of tons]

Forward cost [1] (1975 dollars per pounds)	Reserves	Potential resources			
		Probable	Possible	Speculative	Total
$10	270	440	420	145	1, 275
$15	430	655	675	290	2, 050
$30	640	1, 060	1, 270	590	3, 560
	[2] 140				140
Total supply	780	1, 060	1, 270	590	3, 700
Cumulative number years' supply [3]	17. 3	40. 9	69. 1	82. 2	82. 2

[1] Forward costs are those costs incurred after the geological investigation, land acquisition, and exploration have been completed, and therefore do not represent prices at which uranium oxide will be marketed.

[2] By-product of phosphate and copper production that becomes available independent of forward costs.

[3] Assumes 45,000 tons a year consumption, estimated for 1987.

Source: ERDA, July 1976.

Costs of conversion

It is estimated that in 1977 dollars, it costs about $625 million to build a 1,000-megawatt nuclear power plant. This comes to a cost of about $625 dollars per kilowatt. A 1,000-megawatt plant is adequate to supply the energy needs of a city of about 1 million people. As in the case of coal plants, however, there is considerable regional variation in cost.

The leadtime required for siting, licensing, and construction of a nuclear facility is approximately 8 to 11 years, although the Administration intends to speed up the licensing process, which may cut this period to some extent.

C. Cogeneration

Cogeneration is the production of electricity from steam, heat or other forms of energy produced primarily for purposes other than the generation of electricity.

At present, industry generates steam principally for its use in manufacturing and heating, and only about 30 percent of this steam is used to generate electric power. About one-half of all industrial steam is produced at plants generating 250,000 pounds per hour or more, at each location. Almost one-quarter of the total industrial steam load is produced at plants generating 1,000,000 pounds per hour or more at single locations. A large percentage of this steam, however, comes from package oil and gas fired boilers operating at pressures and temperatures too low for byproduct electric power generation. If the industrial steam base (at plants generating 250,000 pounds or more of steam per hour) were fully utilized, the power generated would provide about 55 percent of industry's electrical requirements.

Beyond that point, additional industrial capacity would generate surplus power which could be sold to near-by utilities. If the contiguous utility declined to purchase and a neighboring utility desired to purchase, the power would have to be wheeled over the transmission lines belonging to the contiguous utility. It is not uncommon to find one utility performing this service for another utility, but it is rare to find a utility wheeling power for an industrial firm.

A number of factors have led to this underutilization of the potential for industrial cogeneration:

(1) Historically low electric rates from central power stations encouraged the substitution of power for steam in some situations, thereby eroding the industrial steam base.

(2) Trained maintenance personnel are required for coal-fired boilers. Gas and oil-fired packaged boilers, which could operate almost unattended are usually not suitable for power generation.

(3) There has been a continual increase in the average size of central power stations relative to industrial power generators. As a result, economies of scale favored central electric power stations.

(4) Competitive policies by most privately owned electric utilities have discouraged electricity generation by any other organization. Rate schedules favored large industrial users and high charges for power to meet only peak requirements made it uneconomical to use the utility as a stand-by source of industrial power.

In addition, it is possible that some industral management has been reluctant to utilize cogeneration due to a lack of familiarity with this process and its potential benefits.

D. General Considerations

Higher prices for natural gas and petroleum products would encourage conservation in three ways: (1) encouraging the substitution of coal and nuclear energy sources for petroleum products and natural gas, (2) encouraging the use of less energy-intensive and more energy-efficient methods of production, and (3) raising the price of the final product and discouraging consumption, and therefore production, of energy-intensive goods. A tax on industrial use of oil and natural gas would be likely to reduce energy consumption in the same three ways.

A credit for coal-burning equipment would reinforce conversion from the use of oil and natural gas but would not necessarily lead to a reduction in overall energy use.

The potential for conservation in the industrial sector is indicated by changes in industrial energy use from 1973 to 1976, a period of rapidly rising energy prices. Although industrial production was the same in both years, energy consumption declined by 5.3 percent.

Future consumption of petroleum products and natural gas by utilities is likely to decline even without any change in prices or increase in taxes. Under the House bill no new utility boilers, and no new industrial boilers above 10 megawatts, may be oil or gas fired. In addition, certain industrial users of oil or natural gas may be required to convert to coal or some other fuel by the FEA, and all utilities will be required to convert by 1990. However, there may be certain exceptions to the foregoing rules for environmental or hardship reasons. Generally these exceptions will be temporary.

Even apart from these regulatory obstacles (to which there could always be exceptions) electric utilities currently plan no new oil or gas-fired plants to meet their base load demand. (Baseload plants are those operated at 70 percent or more of capacity.) Even though the capital cost per kilowatt of capacity of a coal-fired boiler (and necessary scrubber) or nuclear plant is considerably greater than that for oil and gas-fired plants, the lower cost of coal and nuclear fuel per Btu more than makes up for this difference (at least at current price levels). Since the useful life of steam boilers for base-load purposes is approximately 30 years, hardly any base-load electricity will be generated from natural gas or petroleum products after the turn of the century. (Intermediate and peakload units might still use oil, however.) On the other hand, about half of the existing oil or gas-fired plants are 10 years old or less, and rapid conversion of these plants is not likely to occur, even in the face of strong tax incentives.

Industrial firms, however, have much smaller boilers and continue to find oil and natural gas more economical than coal. Large industrial users (30 megawatts or more per boiler) now select coal about half the time for new plants, but coal currently supplies only about 10 percent of all industrial boiler fuel. About two-thirds of all boilers in industry are gas-fired, although gas-fired units currently account for only about one-third of new sales of units used to generate electricity. Oil-fired units comprise almost one-half of new sales, while coal and miscellaneous sources power the remainder.

The enactment of the crude oil equalization tax would speed up the process of conversion, particularly for oil burning utilities. If utilities must pay world prices for petroleum products, then they are likely to substitute new coal or nuclear plants for existing oil facilities even before this conversion is required by law (generally 1990). The oil and natural gas users tax would provide a further incentive in this regard.

II. TAX ON BUSINESS USE OF OIL AND NATURAL GAS

A. Present Law

Under present law, natural gas prices for gas which is sold in interstate commerce are regulated by the Federal Power Commission. Gas which is sold intrastate is not subject to Federal price control.

Historically, the price of natural gas sold in interstate commerce was controlled at levels ranging from about 14 cents per thousand cubic feet ("mcf") to 34 cents per mcf, depending on the area of the country where the gas was produced and sold. Thus, all interstate gas was sold at levels substantially below those prices charged for an equivalent amount of energy in the form of oil (even in periods when oil prices were far below current levels). Beginning in 1974, prices for gas which is newly committed to interstate commerce have been standardized on a national basis and have increased substantially, so that gas newly dedicated to interstate commerce is now selling at a rate of approximately $1.45 per mcf. However, much gas is selling at prices below this rate under old contracts which were entered before the recent round of price increases.

The FPC has authority to permit "spot sales" of interstate gas at higher than controlled prices during limited periods of emergency. In addition, in the Emergency Natural Gas Act of 1977, Congress authorized the President to permit sales of gas at uncontrolled prices to prevent local natural gas emergencies, but this authority expired July 1, 1977. (However, the House bill extends this authority until April 30, 1979.)

The price paid by consumers for natural gas which is delivered to their homes and businesses is regulated at the State level by public utility commissions. Generally, current pricing policies favor bulk industrial users of natural gas. However, these customers are usually "interruptible," which means that in time of shortage, their gas is shut off first.

Under the Energy Supply and Environmental Coordination Act of 1974, the Federal Energy Administration may prohibit new or existing utility power plants or major industrial fuel burning installations from burning petroleum or natural gas if certain findings are made. For existing plants, the FEA must show that the plant has the practical capability to burn coal, that coal and transportation facilities are available, that coal burning would not cause adverse environmental effects, and that, in the case of a power plant, a conversion will not impair the reliability of electric service. For new plants, the FEA may order that coal be used unless the reliability or adequacy of service is likely to be impaired or an adequate and reliable supply of coal is not expected to be available.

B. House Bill

1. Tax Provisions

Imposition of tax

A tax would be imposed on the use of oil or natural gas as fuel in a trade or business. Three levels of tax would be imposed: Tier 1 which would apply to an industrial use where conservation in fuel consumption is feasible; Tier 2 which would apply to uses of oil or natural gas in which conversion to another fuel is feasible; and Tier 3 would apply to electric utilities, industrial producers of electricity using boilers with a total rating of at least 100 megawatts per plant and industrial cogenerating facilities.

The House bill only imposes the tax on the larger industrial and utility users of oil and gas. An exemption is provided which limits the tax only to those firms which use more than 50,000 barrels of oil per year or the Btu equivalent of gas (i.e., 300 billion Btu). In cases of a regional competitive disadvantage, the Secretary of the Treasury may provide additional exempt amounts for individual plants, and he is required to publish the identification of taxpayers and plants which receive additions to their exempt amounts.

Determination of amount of tax

Under the House-passed bill, the tax on Tier 3 (electric utility) uses of oil and natural gas, and the Tier 1 and Tier 2 tax on the business use of oil are imposed at a flat rate. However, the Tier 1 and Tier 2 taxes on the use of natural gas are imposed at variable rates (described below) designed (when the taxes are fully phased in) to make the cost of natural gas fully equivalent (Tier 2) or almost equivalent (Tier 1) to the price of an equivalent amount of energy in the form of No. 2 grade distillate oil (but not including the users tax on oil).

Flat tax.—The tax on Tier 3 uses and on use of oil in Tiers 1 or 2 would be determined according to the following schedules:

	Tax on oil (per barrel)			Tax on natural gas (per million Btu)
Year of use	Conservation tier (Tier 1)	Conversion tier (Tier 2)	Electric utilities (Tier 3)	Electric utilities (Tier 3)
1979	$0.30	$0.30	None	None
1980	.60	.60	None	None
1981	1.00	1.00	None	None
1982	1.00	1.45	None	None
1983	1.00	2.00	$1.50	$0.55
1984	1.00	2.50	1.50	.65
1985 and thereafter	1.00	3.00	1.50	.75

In the case of the Tier 3 tax on the use of natural gas, there would be a cap on the tax so that it would not exceed the amount necessary to make the firm's cost of gas (including the tax) equal to the cost of the residual oil (including the tax) in the region where the gas is used.

Variable tax.—The House bill provides a variable tax on the industrial use of natural gas in Tier 1 and Tier 2 categories which would be determined by subtracting the user acquisition price (per million Btu of gas) and a cost differential from the target price (per million Btu of gas) for the region in which the gas is used. The cost differential will change each year—declining annually from $1.35 in 1979 to $.30 in 1985 and later years for Tier 1 use and from $1.05 in 1979 to zero for Tier 2 use in 1985 and later years.

The exact cost differentials (per thousand cubic feet of natural gas) for particular years are shown on the following table.

	The amount subtracted for Tier 1 is—	The amount subtracted for Tier 2 is—
If taxable use occurs during calendar year—		
1979	$1.35	$1.05
1980	.70	.40
1981	.65	.35
1982	.55	.25
1983	.50	.20
1984	.45	.15
1985 or thereafter	.30	Zero

Since a primary purpose of this tax is to equalize among users the difference between the cost of natural gas and the cost of No. 2 distillate oil, the amount of the tax depends on the price which the business pays for its gas. Generally, the higher the price which the business must pay for its gas, the lower will be the tax necessary to bring the total cost of that gas up to the target level for the year. The natural gas target price is determined by the average regional price of all No. 2 grade distillate oil sold during the preceding calendar year in the region, adjusted for differences in energy (Btu) content between such oil and natural gas. In cases where natural gas is purchased under an interruptible contract, the users tax would be subject to a 10-percent reduction.

Inflation adjustment.—Beginning in 1981, the tax rates would be adjusted annually for inflation that occurs after 1979. The implicit price deflator for the gross national product is to be used as the index of inflation. The index for the calendar year preceding the current calendar year would be used in order to inform the taxpayer as early as possible in the current year what the tax rate would be.

Suspension of tax

The President could suspend the tax for a period up to one year, if he believes it would have an adverse economic effect. A suspension plan would have to be submitted to Congress and would be subject to a veto by either House within 15 days of its submission.

Exemptions from tax

(1) Industrial process use would be exempt from the tax when the use of fuels other than oil or natural gas would materially and

adversely affect the manufacturing process or the quality of the manufactured goods, and when the use would not be economically and environmentally feasible.

(2) An exemption from the tax would be provided to nonindustrial uses of oil and natural gas in residential facilities, in transportation (including pipelines), on a farm for farming purposes, in nonmanufacturing commercial buildings, and in the exploration, development and production of crude oil and natural gas.

(3) Oil and natural gas would be exempt from taxation if used in a facility that was in existence or under construction on April 20, 1977, and which was precluded from using coal by State air pollution regulations in effect on that date or by Federal air pollution regulations. State regulations not in effect on that date would also be grounds for exemption if such regulations were necessary to meet a requirement of Federal law. A regulation of a local agency having jurisdiction over a facility under an approved State Implementation Plan also would be the basis for an exemption.

Reclassification of uses

The Secretary of the Treasury would establish a procedure for reclassifying uses to a category which is taxed at a lower rate or which is exempt from tax. In considering requests from individual firms, the Secretary is to take into account the potential for conversion or conservation in the use of oil and natural gas and would also consider environmental, economic, as well as technological factors relevant to the individual case.

Energy savings estimate

It is estimated that the total energy savings from these provisions, including the users tax, the rebates, and the business energy tax credits (described below) will be between 830,000 and 1,250,000 barrels of oil per day by 1985. It should be noted that this estimate does not take account of the coal conversion regulatory provisions under the House bill (described below in the next section). If these provisions are enacted, the additional savings from the business use tax and rebates would be lower.

2. Non-Tax Aspects of the House Bill

Natural gas pricing

The natural gas pricing policy adopted by title I of the House bill establishes a single uniform price policy for natural gas produced in the United States.

With respect to supplies of new natural gas, a price is provided which is related to delivered domestic crude oil prices. The price for new gas will equal the Btu-equivalent of the average refiner acquisition cost of non-Alaskan crude oil, without regard to the crude oil equalization tax. This price is estimated to begin at a level of approximately $1.75 per million Btu's (Mcf) in the first quarter of 1978. This initial price climbs upward as crude oil costs increase at approximately 10 percent per year. New natural gas eligible for this price is defined as gas that is either produced from an onshore well more than 2½ miles away from or 1,000 feet deeper than a well in existence before April 20, 1977, produced from an offshore well from a lease entered into after April 20, 1977, or produced from a new reservoir.

A flexible special pricing authority is granted to the Federal Power Commission under which it may approve higher prices where needed. This provision assures that maximum price incentives are focused on those areas where the greatest potential exists that the incentives will be effective and encourage production of hard to produce natural gas.

High-priority users, including homeowners, are temporarily insulated from further substantial price increases through incremental pricing provisions. Under the natural gas pricing policy, natural gas price increases experienced by pipeline companies are disproportionately loaded onto low priority users until the delivered price of natural gas to these users reaches equivalency with the cost of substitute fuels. Sales of natural gas with the singular exception of interstate sales of old natural gas under existing contracts, are "deregulated" from the provisions of the Natural Gas Act. While the Federal Power Commission is granted substitute regulatory powers with respect to such deregulated sales, the scope of these powers is more limited than the regulatory powers of the Commission under the Natural Gas Act. The Commission's regulatory powers are limited to prospective application to contract terms and conditions.

Utility rate reform

The bill imposes requirements that electric utility rates must be designed to reflect costs of services and be on a time of day and seasonal basis except where not cost-effective. However, a State may establish lower than cost rates for the essential electric energy needs of residential class electric customers. Also, individual customers may obtain limited exceptions to these provisions upon a showing of significant economic hardship. There are also provisions requiring the gathering of certain information; prohibiting the recovery by electric utility from its electric consumers of certain advertising expenses;

provisions governing the use of automatic adjustment clauses; requirements regarding the establishment of nondiscriminatory rates for small electric systems; implementation of load management techniques; transmittal of information to electric consumers; and procedures for termination of electric service. It also requires State regulatory authorities to prescribe methods for the determination of costs of services and to consider load management techniques. Provision is made for the reimbursement of intervenors in regulatory proceedings and for enforcement and judicial review of utility compliance.

The bill expands the authority of the Federal Power Commission to order interconnections between electric utilities and to order the wheeling of electric power to utilities. It also requires the Commission to issue rules to insure continuance of service; to establish electric utility reliability standards; and, to facilitate the sale and purchase of electricity between electric utilities and cogeneration facilities. In addition, it contains requirements regarding Commission consideration of pro- power and extends the authority of the Commission in addressing posed new rate schedules. Also, it establishes requirements governing the use of automatic adjustment clauses in wholesale sales of electric power and extends the authority of the Commission in addressing any anticompetitive effects associated with the construction of new bulk power facilities.

The bill provides for the establishment of a grant program to improve staffing for State regulatory authorities, extends already existing authority to fund innovative rate structures and establishes a grant program to assist intervenors before State regulatory authorities. It authorizes funds to carry out these programs. In addition, it authorizes the establishment in the Commission of an Office of Public Counsel with standing to become a party in any proceeding, to petition the Commission to seek judicial review of Commission actions.

The bill requires the Commission to undertake a 1-year study of gas utility ratemaking so as to address the effect of incremental and marginal cost pricing, wellhead pricing and declining block gas rates, among other things, on such factors as pipeline and distribution company load factors and demand for and consumption of natural gas. In addition, it establishes standards regarding the recovery of advertising expenses from consumers and termination of service.

It also establishes a 3-year program of grants and loans to encourage municipalities, cooperatives, industrial development agencies, and other nonprofit organizations to develop the existing hydroelectric potential of existing dams at which no such potential has been developed.

Conversion from natural gas and petroleum to coal and other fuel resources

Under title I of the House bill, no new electric powerplant may use natural gas or petroleum as a primary energy source unless the Administrator grants the powerplant an exemption. A temporary exemption may be granted for up to 5 years if a coal supply is not likely to be available, insurmountable site limitations appear to exist, or environmental requirements would be violated. A permanent exemption may be granted if there is no site where coal could be burned in an environmentally acceptable manner at a price which does not substantially exceed the costs of burning imported petroleum or if the powerplant will be operated as a peakload unit.

New major fuel-burning installations (MFBI's) which are boilers may not use natural gas or petroleum as a primary energy source.

The Administrator may grant a temporary exemption from the rule or order for a maximum of 5 years on the same grounds as the exemptions for new electric powerplants or, if the new MFBI is not technically capable of using coal or if it has contracted for a supply of synthetic fuel derived from coal which will not be available for the period of the exemption. A temporary exemption on the basis of unavailability of synthetic fuel may be extended for an additional 5 years.

A permanent exemption may be granted on the same grounds as the exemptions for powerplants or if the use of a fuel other than natural gas or petroleum is not technically feasible. A permanent exemption may also be granted if the applicant certifies a fuel mix will be used and the natural gas and petroleum used in such mix does not exceed in any 12-month period 25 percent of the total Btu heat input of the MFBI (or other minimum percentage needed to maintain fuel efficiency).

Existing electric powerplants are prohibited from using natural gas as a primary energy source if the plants used petroleum as the primary energy source prior to April 20, 1977. If a powerplant used natural gas as a primary energy source on April 20, 1977, it is prohibited from using natural gas in any greater proportion than its average previous use (between 1974–1976 or the first two years of operation if constructed after 1974). In either event no existing electric powerplant may use natural gas after January 1, 1990, unless the Administrator grants the powerplants an exemption from such prohibition.

The Administrator may prohibit by rule categories of existing electric powerplants and MFBI's or by order individual existing electric powerplants and MFBI's from burning petroleum, natural gas or both. It must be technically and financially feasible for the affected powerplants and MFBI's to use coal as a primary energy source. A fuel mix using petroleum or natural gas and coal or other fuels may be permitted where it is technically and financially feasible to do so. A powerplant may be permitted to increase its use of petroleum upon a showing that the petitioner cannot comply with the provisions of the Clean Air Act or State implementation plans.

A temporary exemption from these prohibitions may be granted for existing powerplants and MFBI's on the same grounds as for new powerplants and MFBI's. An additional ground for exemption of existing powerplants is certification by the FPC that no alternative power supply can be obtained without impairing reliability of service. Temporary exemptions granted to MFBI's for unavailability of synthetic fuel may be extended for an additional five years.

A permanent exemption from these prohibitions may be granted to an existing MFBI upon certification by the petitioner that the installation will use a fuel mixture and that the natural gas or petroleum used in such mixture will not exceed, in any 12-month period, 25 percent of the total Btu heat input of the MFBI (or such other minimum percentage as is necessary to maintain fuel efficiency).

A permanent exemption may be granted to an existing powerplant for the use of liquified natural gas upon certification by the EPA that the use of coal by the powerplant would not comply with environmental requirements.

With respect to both powerplants and MFBI's, the EPA must certify the earliest date when the Administrator's orders can be carried out in compliance with the provisions of the Clean Air Act.

The Administrator may prohibit the use of natural gas as a primary energy source in any existing boiler which is used to produce steam for space heating, which prior to April 20, 1977, had the capability to use petroleum, and which consumes 50 Mcf or more natural gas per peak day. The Administrator may additionally prohibit any use which is inconsistent with the purposes of the Energy Act.

An exemption may be granted from any prohibition to a qualifying cogeneration facility if the Administrator finds that the benefits of cogeneration are unobtainable unless petroleum or natural gas is used.

The Administrator may grant a permanent exemption from any prohibition against using natural gas upon a showing that the petitioner owns or is entitled to receive at the point of manufacture synthetic gas derived from coal which in Btu content is equal to or greater than that of natural gas. The petitioner must also demonstrate that all necessary permits for transportation of the synthetic gas have been obtained.

A person who has contracted to receive natural gas affected by these prohibitions may transfer all or a portion of his interests to an interstate pipeline or to another person and receive just compensation therefor. Persons who would have transported or distributed natural gas affected by these prohibitions shall receive just compensation from the person to whom contractual rights to the gas are transferred.

Under certain conditions the President may allocate coal to insure reliability of electric service or to prevent unemployment. If the President determines a severe energy supply interruption exists he may order new or existing electric powerplants and MFBI's to cease burning natural gas or petroleum, notwithstanding applicable environmental requirements. Under certain conditions, the President may stay rules or orders issued under this Part. The President's powers may not be delegated.

C. Administration Position on the House Bill

The Administration generally supports the House bill with the following modifications:

1. The Administration proposes that all nonexempt industrial use of natural gas be taxed at the Tier 2 level, which would bring the cost of natural gas up to the cost of distillate oil (exclusive of the users tax on the oil).
2. The Administration proposes to eliminate the process user exemption and the environmental exemption in the case of natural gas.
3. The Administration proposes that the target price for natural gas liquids (which under the House bill are taxed in the same manner as natural gas) should include the users tax on oil.

D. Other Congressional Consideration

1. Action in the 94th Congress

During the consideration of H.R. 6860, the Senate Finance Committee tentatively decided to provide an excise tax on oil and gas used in business as a fuel. The tax was phased in between 1977 and 1980 for natural gas, and between 1977 and 1982 for oil. When fully effective, the rates were $1 per barrel for oil and 18 cents per thousand cubic feet for gas. There were exemptions for natural gas used in gas pipeline compressors, extraction of oil or gas, vessels, aircraft, apartments and other residential facilities, mining, textiles, glass, farming, existing facilities for generating electrical power (in this latter case only until 1982 and only if either EPA certified that environmental requirements force use of oil or gas or FEA certified that there is no economicaly feasible alternative to use of oil or gas), vehicles (but only as to diesel fuel or where gasoline would be exempt under present law—e.g., sales to State or local governments), and tax-exempt educational, charitable, or religious organizations (but not for these organizations' unrelated trades or businesses). The FEA was to have made a report as to factors bearing on uses which should be exempt from this tax.

This provision was never included in any reported bill.

2. Senate action in the 95th Congress

Conversion from natural gas and petroleum to coal and other fuel resources

On September 8, 1977, the Senate passed S. 977, the Natural Gas and Petroleum Conservation and Coal Utilization Act of 1977.

Under the provisions of the bill, new electric powerplants and certain new major fuel-burning installations are prohibited, with specified exceptions, from using natural gas or petroleum as their primary energy source. This restriction does not include either the fuel required for start-up, testing, and flame stabilization. In the case of major fuel-burning installations, this restriction does not apply to the fuel required for certain uses, including feedstock uses. In addition, major fuel-burning installations which burn 300 million Btu's or less of petroleum daily are exempt. This exemption is subject to repeal after a one-year study by the FEA.

Temporary exceptions (up to five years) from these prohibitions are provided for if fuels other than petroleum or natural gas are not available; if physical, environmental or legal factors preclude compliance; or if reliability of operation would be impaired by compliance.

Permanent exemptions may be granted with respect to the use of petroleum if the applicant can show that physical, environmental or legal factors would preclude compliance; or the cost of using coal or other fuels would substantially exceed the cost of using imported oil. In the case of new electric powerplants, the applicant must also show that there is no reasonable available alternative site where coal or other fuel could be used in lieu of natural gas or petroleum and satisfy the requirements of the act. Permanent exemptions may be granted with respect to petroleum where necessary for the attainment and maintenance of primary ambient air quality standards which are based upon the protection of public health. Peak load electric powerplants may be exempt from the petroleum prohibition if the applicant certifies that the facility will be operated only for peak load purposes.

S. 977 also contains provisions allowing the Administrator to exempt from requirements and prohibitions of the bill those electric powerplants and major fuel burning installations which either are operated only for standby and emergency purposes or are intended to be retired. These provisions would avoid requiring capital investment to be made with respect to facilities that are operated infrequently or are old and near replacement. Permanent exemptions from the requirements to use coal or other fuels also may be granted for certain cogeneration facilities upon a showing that the economic and other benefits of cogeneration are not obtainable unless petroleum can be used by such facility. Permanent exemptions also are authorized if the applicant demonstrates to the satisfaction of the Administrator of FEA that compliance with the requirements and prohibitions of the bill would not be in the public interest.

Existing electric powerplants are prohibited from using natural gas as their primary energy source after January 1, 1990. Temporary exceptions (up to five years) and permanent exemptions similar to those for new facilities are provided after 1990 for reasons similar to those which would exempt new facilities from compliance.

Provision is made for restricting the reversion of existing electric powerplants and major fuel-burning installations from either coal to natural gas or petroleum, or in the case of existing electric powerplants, from petroleum to natural gas.

Installations capable of using mixtures or combinations of coal, and natural gas or petroleum, may be ordered to use the minimum feasible amount of natural gas or petroleum in combination with coal.

In addition, the coal conversion provisions of the Energy Supply and Environmental Coordination Act, as amended, are extended. Under these provisions existing electric powerplants and major fuel burning installations capable of using coal or other fuels may be ordered by the Administrator to cease using natural gas or petroleum. However, the basis for temporary exceptions and permanent exemptions contained in this Act shall also apply to such orders.

In those instances where an existing electric powerplant or major fuel-burning installation is unable through normal financing means to finance the necessary equipment to use coal or other fuel in lieu of natural gas or petroleum and comply with applicable environmental requirements, S. 977 authorizes coal conversion loans and loan guarantees for such equipment. In addition, the Administrator is authorized to compensate for the additional capital and operating cost necessary when a request for a permanent exemption from any requirement or prohibition to use coal or other fuel in lieu of natural gas or petroleum is denied for an existing installation.

An optional "systems compliance plan" option is provided for those electric utility systems which operate on intrastate natural gas. In addition, impact assistance is authorized for additional public facilities or services or housing to regions of the United States impacted by expanded coal production.

The bill provides that a new electric powerplant or installation unable to use natural gas under contract may sell its rights at a price to be determined, including an amount to compensate a pipeline or distribution company entitled under the contract to transport the gas.

S. 977 provides authority in certain emergency situations to allocate coal, to ban temporarily the burning at certain electric powerplants and installations of natural gas or petroleum, and to stay the prohibitions of the statute to deal with supply interruptions and shortages.

The bill authorizes $100 million for rehabilitation of branch and spur railroad lines to carry coal and coal products.

The provisions of the Natural Gas and Petroleum Conservation and Coal Utilization Policy Act of 1977 are to take effect 180 days after the date of enactment. Prior to that time, however, the Federal Energy Administration would be specifically empowered to promulgate regulations to implement the program.

Natural gas pricing

On September 13, 1977, the Senate Commitee on Energy and Natural Resources agreed to report the Administration bill, as introduced, on natural gas pricing to the Senate without prejudice or recommendation.

E. Areas for Committee Consideration

Economic impact of the users tax under the House bill

The users tax contained in the House bill would increase the prices of electricity and manufactured goods and would increase fuel costs in some regions more than others.

It is estimated that the impact of the user tax on the prices of goods sold to consumers and of equipment sold to businesses will be small, perhaps in the neighborhood of 1 to 2 percent. As table 4 shows, the cost of purchased energy is approximately 2 percent of the value of shipments in manufacturing industries. Thus, even if energy prices were to double, the direct impact of this increase on the average price of manufactured goods would be only about 2 percent.

Total industrial fuel costs are expected to rise between 10 and 15 percent as a result of the users tax. Average cost increases for natural gas and petroleum products would be greater than this, but the increase in costs of coal and electricity resulting from this provision would be less. Cost increases could be minimized by both the greater use of coal and the additional conservation of oil and gas which would be stimulated by this provision. However, the user tax and credits are likely to stimulate investment in new facilities, some of which would replace existing facilities still in good working order.

Although energy costs will rise appreciably, the relatively small importance of energy in total costs implies that price effects of the users tax will be relatively small on an aggregate basis. However, particular industries may have relatively large increases. As table 4 indicates, there is considerable variation among industries in the importance of energy purchases, and the variation would appear to be even greater if the manufacturing sector were divided into smaller industry groups. Thus, the paper, chemicals, and stone, clay, and glass industries are likely to increase their product prices more than other industries. (Under the House, bill however, there are exemptions from the user tax for certain process uses. These exemptions would reduce the impact of the tax on many industries.)

Largely because of the variable tax on natural gas, the users tax will have an uneven regional impact. The variable tax will be largest in those areas where average gas prices will be lowest: e.g., the South Central region, which produces much of the nation's natural gas. Thus, the variation among regions in the cost of energy to industry will be reduced by the House bill. Currently, there are large variations among regions in the average price of natural gas. For example, the average cost of natural gas to industrial users in the Southwest in 1975 was approximately $0.70 per mcf, while in New York and New Jersey, the average cost was approximately $1.50 per mcf. Approximately $0.50 of this difference was due to transportation (pipeline) costs, while the remainder is due to lower wellhead prices prevailing for gas sold in the gas producing regions. The variable gas tax would virtually eliminate the variation in costs resulting from both these causes. Average energy costs would still vary by region, however, because of variation in transport cost for coal and in electricity prices. The users tax also has a regional impact because the industrial use of oil and gas as a fuel is much greater in oil and gas producing States than elsewhere in the country.

TABLE 4.—*Value of shipments and the cost of purchased fuels and electricity for manufacturing industries, 1974*

[Dollar amounts in millions]

Industry group	Value of shipments	Cost of purchased energy	Cost of purchased energy as percent of value of shipments
Food and kindred products	$162, 014	$1, 449	0. 9
Tobacco products	7, 140	39	. 5
Textile mill products	32, 892	692	2. 1
Apparel	30, 551	171	. 6
Lumber and wood	26, 853	482	1. 8
Furniture and fixtures	13, 197	128	1. 0
Paper and allied products	41, 665	1, 905	4. 6
Printing and publishing	35, 822	244	. 7
Chemicals	83, 801	3, 428	4. 1
Petroleum	58, 876	1, 262	2. 1
Rubber	27, 902	538	1. 9
Leather	6, 177	53	. 9
Stone, clay, and glass	26, 620	1, 554	5. 9
Primary metals	95, 618	4, 193	4. 4
Fabricated metal products	67, 570	820	1. 2
Machinery	92, 487	776	. 8
Electrical equipment	65, 804	607	. 9
Transportation equipment	108, 245	829	. 8
Instruments	20, 865	104	. 8
Miscellaneous manufacturing	14, 044	129	. 9
Total, manufacturing	1, 017, 873	19, 462	1. 9

Source: 1974 Census of Manufacturers, Bureau of the Census, Department of Commerce.

Structure of the tax

Under the House bill, the structure of the tax on natural gas is intended to equalize the cost of natural gas to all industrial and utility users, regardless of the price they are currently paying under contracts with their suppliers. Thus, a business or utility which is currently paying a relatively low price for natural gas would be subject to a relatively high tax, while a business or utility which is currently paying a relatively high price would be subject to a relatively low tax.

This approach has the advantage (in terms of conservation) of bringing the cost of natural gas up rapidly for all industrial and utility consumers. However, some would argue that this approach is inequitable to beneficiaries of existing low-cost natural gas contracts because it may cause large, sudden increases in their gas costs. In addition, the approach under the House bill creates certain regional distortion in the effective rate of the tax which many feel are undesirable.

Another problem under the House bill is that certain firms now pay relatively low prices for natural gas because they are "interruptible." The existence of some interruptible customers benefits the gas distribution system by allowing the pipeline to operate on a year-round basis and by providing an easy means for determining whose gas will be shut off in times of shortage. If the natural gas users tax is structured in such a way that all users will pay the same after-tax price for gas, no one will have an incentive to purchase gas on an interruptible basis.

An additional technical problem with the House bill is that utilities and industrial users of natural gas may have little incentive not to renegotiate their contracts with current suppliers to provide for upward price adjustments. If the committee should decide to adopt the House bill in this regard, it may be necessary to provide some mechanism to discourage renegotiation.

There are, of course, ways in which these technical problems can be handled. The House bill already contains a mechanism to provide some incentive for interruptible contracts. With regard to the renegotiation of contracts, the committee might provide, for example, that the tax rate would equal 90 percent of the difference between the actual selling price of the gas and the Btu equivalent price of distillate fuel oil, rather than 100 percent.

However, another approach which the committee might wish to consider would be a flat rate of tax on business use of natural gas. Based on the Administration's projections of oil and natural gas prices and an adjustment of tax rates for inflation in 1981 and thereafter, the following flat tax rates would have the same average effect on industrial fuel costs as the variable tax contained in the House bill:

Tax per million Btu of natural gas

Year of use	Upper tier	Lower tier
1979	$0.65	$0.35
1980	.95	.65
1981	1.00	.70
1982	1.15	.85
1983	1.20	.90
1984	1.30	1.00
1985	1.45	1.15

The tax schedule for years after 1985 would continue to be adjusted for inflation. As a safety valve, the commitee might wish to provide that if the proposed tax on the industrial and utility use of gas raised the price of natural gas above the price of an equivalent amount of oil (including the oil users tax), then the gas tax would be capped at this level. However, at the rates suggested in the above table, it is unlikely that this would occur, because natural gas is selling far below the price of an equivalent amount of oil in most cases.

The process use exemption

Under the House bill there is an exemption from the tax for the process use of oil or natural gas in cases where the use of coal or another substitute fuel would have a material adverse affect on the manufacturing process, or on the product, and in cases where the use of any substitute fuel would be environmentally or economic infeasible. The legislative history further explains the intention of this provision and provides some examples of process uses which would probably be exempt under current technology.

The problem in connection with this exemption occurs because there are numerous kinds of process uses of oil and natural gas in many different industries. It would clearly be desirable to have more certainty in this area. Yet it is impossible for the Congress to decide at this point which of these various uses fairly could be said to have a potential for conservation or conversion. Moreover, it is clear that there are some process uses which do have such potential, for example, cement clinker rotary kilns and horizontal lime kilns. (Many existing kilns already use coal.)

Under the House bill, the Secretary of Treasury is to classify the various process uses in accordance with the standards of the bill, to determine whether or not they are taxable.

Another approach which the committee might wish to consider would be to specify now a list of process uses which would be subject to tax. In addition, a procedure could be established whereby the Administration could add to this list, subject to a 60-day legislative veto by either House of Congress. In this way, it should be possible to provide both equity and clarity, without having to resolve all of the complicated issues in this area at this time, and without unduly weakening the impact of the tax, because those process uses which do have a potential for conversion or conservation would either be taxable, or could be added to the list of taxable uses through a relatively simple procedure.

Moreover, under the House bill, virtually all Tier 1 uses are process uses. To the extent that there are relatively few process uses which would be taxable under this approach and considering that most of these taxable uses would have potential for conversion, as well as conservation, it might be possible to simplify the tax somewhat by eliminating Tier 1. Thus, all taxable uses of oil and natural gas (other than by a utility) could be taxed at the same rate.

Reclassification procedure

Under the House bill there is a provision allowing the Secretary of the Treasury to reclassify uses which would be otherwise taxable under the provisions of the bill into either a lower tier or into an exempt category, where he finds, on a case-by-case basis, that such a reclassification would be consistent with the conservation and conversion purposes of the bill. In other words, where it is determined that in a particular situation, a business has no significant conservation and conversion potential, the Secretary could reclassify that business, possibly to an exempt category.

This procedure has certain advantages because it allows the Secretary to exempt businesses which have no energy savings potential without the Congress having to resolve all the issues which may arise in individual cases. However, it might be desirable to spell out in somewhat more detail than was done in the House bill the kind of circumstances under which a reclassification might be appropriate. For example, some of the problems in this area may arise because of a firm's inability to invest rapidly in equipment eligible for the credit against the tax (discussed in the next section). (Generally, a 100 percent credit is available but there is no carryover of taxes paid so that to fully utilize the credit the taxpayer must make his conversion expenditures as his tax is accrued.)

However, this problem could also be dealt with through the reclassification procedure. For example, it could be spelled out in the legislative history that where a utility establishes to the satisfaction of the Secretary that it is beginning conversion as rapidly as is practicable under the circumstances, and that its total expenditures for conversion throughout the period before 1990 (when the rebate will expire) will at least equal the cumulative tax liability for that period, then it might be appropriate for the Secretary to grant a temporary reclassification to the utility, until such time as it could begin conversion.

Coordination with regulatory program

Under the Ways and Means Committee bill, there was an additional exemption from the users tax to cover cases where a business or industry had received an exemption from the mandatory conversion program under Title I of the House bill. However, both the House Ad Hoc Committee on Energy and the House deleted this exemption.

On initial consideration, such an exemption appears to have some merit. One problem with this approach, however, is that it had a substantial adverse impact on the energy savings generated under the conversion program. This loss in energy savings was estimated at between 250,000 to 400,000 barrels of oil per day.

There are several other problems with this approach. First of all, the regulatory program is an all-or-nothing situation. Under that program, the Secretary of Energy must either grant an exemption or impose a flat prohibition on the use of oil or natural gas by a business or utility at a particular location. Faced with such a choice, the Secretary of Energy might often feel obligated to grant the exemption even where there was evidence that use of an alternate fuel source might be possible. The users tax, on the other hand, leaves the decision up to the individual businessman, but imposes a tax to make clear to him that he is using up rapidly dwindling national resources.

Second, the regulatory program and the tax program are not completely consistent in their overall approach to the issues of conversion. The regulatory program operates on a plant-by-plant basis. The tax program, on the other hand, provides a combination of tax and incentives (i.e., the tax rebates, discussed below) which are available on a firm-by-firm basis. Thus, even if a firm had a plant which could not use an alternate fuel source, rebates of the users tax generated from that plant might provide the capital for the firm to convert or construct another plant which did use coal or another alternate fuel source. (The utilities and the 1,400 large industrial firms to which the tax applies typically have many individual plants.)

Finally, to the extent that there are firms which have no conversion or conservation potential, the reclassification procedure, as described above, is available to enable such a firm to petition for an exemption. Under the legislative history of the House bill, it is already clear that it would be appropriate for the Secretary to grant reclassification under circumstances where it can be established that a firm cannot use an alternate fuel source and has no significant conservation or conversion potential in any of its plants.

Technical problems

As explained above, if the committee prefers the variable tax approach adopted under the House bill, it might want to deal with several technical problems. Under the House bill, there is a $1 reduction in the tax for each $1 of increased natural gas cost. Thus natural gas users may have little incentive not to renegotiate their contracts with current suppliers to provide for upward price adjustments. The committee could discourage this by lowering the tax from 100 percent to 90 percent of the difference between the users' cost and the target price.

Another technical problem concerns the treatment of gas purchased under an interruptible contract. The House bill provides for a 10-percent reduction in the tax on such gas, but this may provide very little incentive to choose interruptible rather than firm service. For example, if the target price is $3.00 and the cost of gas under firm service is $2.90, the tax would be 10 cents, and the total cost $3.00. Interruptible service may cost $2.60, but even with the discount, the tax would be 36 cents [.9× (3.00−2.60)], for a total cost of $2.96. Thus, the cost of interruptible gas would be only 4 cents less than firm gas, and very little incentive would be provided for choosing interruptible service. More incentive could be provided by specifying a 10-percent reduction in the target price for such gas, instead of a reduction in the tax.

A third technical problem concerns the imputed cost of gas used by the producer or a related firm. The House bill provides that for the purpose of computing the tax, the cost shall be assumed to be the maximum lawful price permitted under Federal law. However, not all gas sales are regulated under Federal law. The committee may wish to specify that the imputed price shall be determined as if sales of such gas were regulated under Federal law.

A fourth technical problem concerns the cap on the utility (Tier 3) tax on gas, which specifies that the tax cannot be greater than the difference between the regional cost of residual fuel oil (including the user's tax) and the user's cost of natural gas. It might be desirable to simplify the tax by computing this "cap" in a manner similar to the tax on industrial users. Essentially the same result as the House bill could be achieved in a much simpler fashion by making the cap on the utility gas tax equal to the Tier 1 tax on gas.

The committee may also wish to clarify the treatment of fuel used in industrial cogeneration facilities. It may be appropriate to allow the Treasury to set performance and efficiency standards for those facilities whose fuel use is to receive favorable Tier 3 tax treatment. Another approach might be to adopt a pro rata rule based on the ratio of electrical energy to the total energy produced by the facility.

The committee may wish to consider a change in the taxation of fuel used in the heating of warehouses. Under the House bill, it is taxed only if the warehouse is an integral part of a manufacturing, processing, or mining facility.

The committee may also wish to prevent the possibility that several firms may set up separate entities, each of which could qualify for a 50,000-barrel exempt amount. For example, the committee could provide that any use of fuel by a partnership is taxable to the partners.

III. CREDIT AGAINST TAX ON BUSINESS USE OF OIL AND NATURAL GAS

A. Present Law

None.

B. House Bill

Under the House bill, a taxpayer may elect a credit against the user tax of $1 for each dollar of qualified investment, up to 100 percent of the taxpayer's oil and natural gas user taxes. If the amount of investment is in excess of the amount of user taxes for the year, a carryforward of this investment is permitted against user taxes in future years. Any user tax liability for 1979 and 1980 may be carried forward to 1980 and 1981.

Utilities would be allowed to carry forward qualifying investment expenditures to offset user tax liabilities incurred beginning in 1983. Utilities would be allowed a credit to the extent that old oil and gas boilers are replaced or phased down for peakload or standby use (1,500 hours or less a calendar year). The extent to which this credit is flowed through to consumers in the form of lower prices is left to the discretion of State regulatory agencies.

Where a phased-down oil boiler is used between 1,500 and 2,000 hours in a calandar year, a penalty equal to the use tax would be imposed. Taxes paid in such cases would not be available for offset by qualified investment expenditures. Where old boilers are used more than 2,000 hours in a calendar year, there would be a recapture of credits against tax.

The credit would not be available after 1990, except for qualified property on which construction had begun.

Qualified energy investment for which a credit against the user tax is allowed includes the cost of alternative energy property placed in service during the year or, if the taxpayer elects, the progress expenditures made for that property during the year. It does not include a building or its structural components and does not include property to be used in the busines of leasing. It includes—

(1) a boiler whose primary fuel is an alternate substance,

(2) a burner and equipment necessary to supply fuel to a combustor other than a boiler for which the primary fuel is an alternate substance,

(3) equipment used in the production of energy by nuclear, hydroelectric, or geothermal power other than the fuel, steam, turbines or equipment beyond the turbine stage,

(4) equipment for converting an alternate substance into synthetic gas,

(5) pollution control equipment required to be installed in equipment described above (other than equipment required to be installed on a facility using coal as of April 20, 1977),

(6) equipment used for unloading, transferring, storing, reclaiming from storage and preparation of an alternate substance for use in the equipment described above or in a facility which uses coal as a feedstock for products other than coke, and

(7) the costs for plans and design for equipment described above.

An alternate substance would be a fuel that is not oil, natural gas or their products.

The bill allows a partial credit for the expenses of modifying an existing electric generating facility using oil or natural gas to use a mixture of oil and an alternate substance.

The taxpayer could receive the regular investment tax credit on his qualified energy investment expenditures only to the extent that a credit against the use tax was not claimed for the same investment outlay.

C. Administration Position on the House Bill

The Administration generally supports the provisions of the House-passed bill with the following modifications:

1. The Administration proposes to limit the rebate to utilities to $125 for each kilowatt of oil- and gas-fired generating capacity replaced or phased down.

2. The Administration would modify the House bill to provide that those who receive the users tax rebate would also be eligible for the regular investment credit.

D. Other Congressional Consideration

At the time of its consideration of the business users tax in 1975, there was no proposal before the Finance Committee concerning a possible rebate of that tax.

E. Areas for Committee Consideration

Coordination of the rebate with the regular investment credit

Under the House bill, those who elect the users tax rebate are not eligible to receive the regular investment credit. The argument supporting this approach is that business or utility should not receive the regular investment credit where the capital to purchase alternative energy property is already supplied by the Government in the form of the 100-percent users tax rebate. (Alternatively, it might be said that the capital is furnished by the customers, to the extent that the cost of the tax is passed through in the form of higher prices.) The business would be allowed to take depreciation deductions for the full cost of the property and would be entitled to receive the regular investment credit to the extent that the cost of the alternative energy property exceeds the amount of users tax rebate available to the business.

On the other hand, one could argue that the cost of the alternative energy property is not fully covered by the rebate even where the business does receive a 100-percent tax rebate. This might be true in situations where, for example, a business was prevented by circumstances from fully passing through the increased cost of fuel resulting from the users tax to his customers. In the case of utilities, to the extent to which a cost passed through would be available would be determined by State rate-making commissions.

Possible limitation on the amount of the rebate

The Administration proposes that the amount of the credit available to utilities for investments in alternative energy property would be limited to $125 per kilowatt. The Administration argument for this is that in the case of some businesses, if no limitation is imposed, the business will use up its entire rebate while converting only some of its plants and equipment to coal and alternative fuel sources. The Administration believes that by placing a limitation of $125 per kilowatt, the incentive for conversion will apply to more plants, and that substantial additional savings of oil and gas will occur.

While this may be true in certain cases, it should be noted that in the case of other businesses, the Administration approach would provide less incentive, and might also place certain businesses in a difficult financial situation because more of the cost of conversion would have to be paid from the business' own resources rather than through the rebate.

Treatment of hydroelectric power

Under the House bill, an incentive is provided for conversion to alternative fuel sources, including hydroelectric power, but provides that qualifying investments do not include structures or equipment at the turbine stage and beyond. In the case of most alternative energy sources, this definition works reasonably well. However, in the case of hydroelectric power, the definition does not work well because there are few, if any, expenditures which would qualify for the rebate. Therefore, the committee might wish to provide that in the case of hydroelectric power, dams would qualify as alternative energy property.

Under present law, the investment tax credit is denied to public utilities if regulatory commissions require that the utility flow through the credit as lower prices to customers more rapidly than would occur under either one of two formulas: the rate base reduction method or the ratable flowthrough method. The purpose of this restriction is to insure that regulatory commissions do not nullify the effect of the credit in stimulating investment; the restriction requires that the commission treat the tax reduction in a manner somewhat similar to that in which it would treat a reduction in the price of eligible equipment. The Ways and Means Committee included in its version of the energy bill a similar restriction on the coal conversion credit against the tax on business use of oil and gas, but this provision was deleted on the House floor as a result of an amendment by the Ad Hoc Energy Committee.

If the utility purchases equipment worth $100, a regulatory commission will normally allow the utility's prices in each year of the useful life of the equipment to reflect both the depreciation on the $100 cost of the equipment and a rate of return on the capital invested in the equipment (the rate base), which is initially valued at $100 and gradually falls to zero as the assets depreciates.

If the price of equipment were $90 instead of $100, the regulatory commission would "flow through" this reduced cost to consumers in two ways: (1) by only allowing them to include in their costs $90 depreciation over the life of the asset rather than $100, and (2) to earn a rate of return on only a $90 rate base, rather than on a $100 rate base. The utility would have an incentive to make additional investments because some investments which were uneconomic at an equipment price of $100 would become economic at $90.

Under the ratable flowthrough option of present law, the commission can require the utility to reduce its rates by a pro rata share of the 10-percent investment credit in each year of the useful life of the equipment, which is essentially equivalent to the depreciation adjustment referred to above in the case of a $10 reduction in equipment prices. The commission continues to assume, however, that the rate base on which the rate of return is computed is equal to $100 rather than $90. Thus, the utility is allowed to charge prices high enough to permit the shareholders to earn a return on the 10 percent of the cost of the equipment which has, in effect, been provided by the Government through the investment credit.

Under the rate base reduction option of present law, regulatory commissions are allowed to force utilities to lower rates to reflect a rate of return on the $90 cost of the equipment supplied by the shareholders themselves, rather than the full $100, but the commissions are not also alowed to force utilities to lower prices to flow through any part of the credit itself, so that depreciation costs for ratemaking purposes continue to assume the full $100 cost of the equipment, not $90.

For the investment credit to be treated the same as a 10-percent reduction in the price of equipment, it would be necessary to flow through to consumers the amounts flowed through under both the ratable flowthrough and rate base reduction methods of present law, rather than force regulatory commissions to flow through one or the other.

Treatment of coal conversion credit for utilities' ratemaking

The Ways and Means Committee's version of the energy bill would have denied the coal conversion credit against the tax on business use of oil and gas in cases where it was flowed through to customers faster than would be the case under the rules presently in effect for the investment credit, as explained above. This provision was deleted on the House floor, but had it been enacted, it would have been subject to varying interpretations. Nominally, the coal conversion credit equals 100 percent of the cost of qualifying equipment, so in one sense it is equivalent to a 100-percent investment credit. However, a taxpayer who claims the coal conversion credit loses a business deduction for the amount of the tax offset by the credit and in return receives a stream of depreciation deductions for the full cost of qualifying equipment.

For a taxpayer in the 48-percent bracket, the loss of the deduction for the tax causes an additional income tax payment of 48 percent. Thus, the credit against the users tax is equivalent to a 52-percent investment credit. In addition, utilities are allowed a depreciation deduction for this 52 percent, even though the utility's funds are not used for this portion. The value of these extra depreciation deductions, which are allowed over the life of the equipment, depends on the utilities' interest rate and on the useful life of the equipment. For a typical utility boiler, this benefit is worth approximately 3 percent of the value of the equipment. Thus, the total value of tax credits and deductions is approximately 65 percent of the value of the equipment. Thus, the committee may wish to provide that this tax benefit is flowed through to customers no more quickly than over the life of the equipment.

In any case, it is not clear that the same anti-flowthrough rules applicable to the investment credit are appropriate for the coal conversion credit. Because in most cases the tax on utilities' use of oil and gas will immediately be passed on to their customers as higher prices, it can be argued that the customer should eventually also receive all of the benefit of the coal conversion credit against that tax. This would require anti-flowthrough rules which are more liberal than those presently in effect for the investment credit.

As it passed the House, the energy bill contains no anti-flowthrough at all. This is not an appropriate result because it permits regulatory commissions to flow through the credit so quickly that the investment incentive is reduced or eliminated, and funds are not provided to utilities to finance coal conversion. In the extreme case in which the commission requires the utility to flow through all of the credit in the year it is claimed (which is called immediate flow through), there would be no investment incentive at all from the credit and no funds to finance conversion would be provided through the tax rebate mechanism.

A possible solution to this problem would be for the committee to adopt an anti-flowthrough rule more liberal than that now in effect for the investment credit. Under such a rule, the coal conversion credit could be denied in cases where the regulatory commission requires that it be flowed through to customers more rapidly than would occur under both ratable flowthrough and rate base reduction with respect to an equivalent investment credit. The equivalent investment credit would be the rate of the coal conversion credit (100 percent in the House bill) adjusted for the loss of the deduction for the users tax and for the value of the depreciation deductions on the portion of its investment not paid for with the utility's funds. For long-lived equipment like boilers, the equivalent investment would be about 65 percent. For short-lived equipment, it would be higher.

Under such a proposal, all of the benefit from the coal conversion credit would be flowed through to customers over the life of the asset. In terms of investment incentives, such a rule would mean that the coal conversion credit would be equivalent to a percentage reduction in the price of equipment equal to the equivalent investment credit; that is, an 80–100 percent reduction in price.

Technical problems

There are certain technical problems in the computation of the credit which should be clarified or corrected either in the bill or committee report.

1. Provisions should be adopted to prevent utilities from meeting the "replacement or phasing-down" requirement solely by phasing down one old boiler and phasing-up another old boiler and treating the "old boiler" as phased down for purposes of allowing a credit for a new boiler. Replacement of a previously

phased-down boiler also should not make a new boiler eligible for a credit.

2. Rules should be provided for the treatment of partnership and joint ventures so that firms may obtain credit for investments made by any partnership in which the firm is a partner.

3. It should be made clear that a firm electing the user tax rebate could also obtain its ESOP investment credit.

4. Consideration should be given as to whether the election of the users tax credit should be made on a firm-by-firm basis as in the House bill, or with respect to some smaller unit, such as plant, boiler, etc.

5. Technical adjustments are needed to coordinate the recapture rules with the penalty tax for 1,500 to 2,000 hours use of an oil boiler after the 7-year recapture period has expired.

6. The statute should provide an "Act of God" rule now contained in the House Committee Report where a phased down old boiler is used solely by reason of an "Act of God".

7. It should be made clear whether or not electricity is an "alternative substance". Allowing a credit for equipment (such as a heater) using electricity could allow two taxpayers a credit where the boiler producing the steam generating the electricity also obtained a credit, or could allow a credit where no gas or oil saving is produced because oil and gas was used to generate the electricity.

8. Further clarification should be provided as to what constitutes alternative energy property, especially for boilers and nuclear energy.

9. The House bill provides a full credit for property at least 50 percent of whose fuel is on alternative substance. The committee may wish to raise this percentage to 75, and to provide a partial credit for equipment whose fuel contain a lower proportion of alternative substances.

10. The committee may wish to allow a credit to the lessee of alternative energy property used by the lessee under rules consistent with the investment tax credit lease provisions.

11. Under the House bill it is not altogether clear whether a credit is available in situations where coal is used to produce both coke and synthetic gas made from coke. Since coal is already used to produce coke, there is little need to provide additional incentive in this area. Therefore, the committee may wish to clarify that the credit is not available in the case of equipment used to convert coal into coke or coke gas.

12. The House bill provides no credit for equipment which uses coal as a feedstock for the production of chemicals or other products, but it does provide a credit for coal handling equipment associated with such facilities. The committee may wish to provide a credit for the equipment which directly uses the coal as a feedstock.

IV. BUSINESS ENERGY CONSERVATION, CONVERSION AND ADVANCED TECHNOLOGY TAX CREDITS AND DEPRECIATION CHANGES

A. Present Law

Investment tax credit

Under present law, an investment tax credit of 10 percent (which reverts to 7 percent after 1980) is allowed generally for tangible personal property which is placed in service in a trade or business. (The credit can be as high as 11½ percent for corporations with qualified employee stock ownership plans.) However, structural components of buildings, including insulation, storm windows and doors, solar energy equipment, etc., generally do not qualify for the credit. Otherwise eligible property placed in service in hotels and other businesses which cater to transients is eligible for the investment credit, but property placed in service in hotels and apartments which have predominantly permanent residents does not qualify for the credit.

The investment credit is also allowed for tangible property (other than buildings or their structural components) which is used in manufacturing, production, extraction, or as an integral part of furnishing transportation, communications, or electrical, gas, or other utility services, even though such tangible property may otherwise be considered real (and not personal) property under local law.

The extent to which the investment credit is available depends upon the estimated useful life used to depreciate or amortize the property for tax purposes. The determination of the useful life is made at the time the property is placed in service. No investment credit is allowed if the property has an estimated useful life of less than 3 years. Where the useful life is greater than 3 years but less than 5 years, the investment credit is allowed on one-third of the taxpayer's cost for the property; if the useful life of the property is greater than 5 years but less than 7 years, the credit is allowed on two-thirds of the cost, and the credit is allowed on the entire cost where the property has a useful life of 7 years or more. If the property on which the investment credit was claimed is later sold or otherwise ceases to be qualified property for the taxpayer before the end of its estimated useful life, the credit may be partially or entirely recaptured to reflect the taxpayer's reduced holding period.

Generally, the amount of the investment credit a taxpayer may apply against his income tax liability in any one year cannot exceed the first $25,000 of tax liability plus 50 percent of the tax liability in excess of $25,000. Special limitations have been provided for public utility property, under which the 50 percent limit was increased to 100 percent for 1975 and 1976, and is 90 percent for 1977, after which it declines by 10 percentage points in each succeeding year until it returns to the generally applicable 50-percent limit in 1981. Similar increases in the tax liability limitation are available (under the Tax Reform Act of 1976) to railroads and airlines, which are allowed to apply their investment credits against 100 percent of their tax liability for 1977 and 1978, and the limitation is reduced by 10 percentage points in each subsequent year until it returns to 50 percent in 1983.

Investment tax credits are not refundable. However, credits which are not applied against tax liability in the year they are earned may be carried back for 3 taxable years and carried forward for 7 years. In applying credits against tax liability for a particular tax year, the first-in first-out method is generally required, under which the credits earned in prior tax years are applied first, then the credits earned in the current year or later years are used.

Depreciation and amortization

Present law also allows taxpayers to claim depreciation or amortization deductions are to reflect the reduction in the taxpayer's cost basis in the property due to use of the property and obsolescence.

Items of property which qualify as depreciable or amortizable property include buildings, machinery and equipment. Land is not depreciable, but a real property interest may be allowed depletion, if it is subject to mining of natural resources or oil and natural gas production.

The taxpayer may claim depreciation deductions over the period which is the estimated useful life of the particular property. The estimated remaining useful life generally may be redetermined during the life of the asset where the change in useful life is significant and there is a clear basis for the redetermination.

Present law authorizes the use of the straight-line method of depreciation (under which depreciation deductions are claimed ratably over the useful life of the asset) or one of several accelerated methods, such as the double declining balance and sum-of-the-years' digits methods, under which deductions in the early years of the useful life are substantially greater than those available under the straight-line method.

In order to reduce uncertainty about the proper useful lives for depreciation of business and productive assets, the Congress has approved the class life asset depreciation range system (ADR). Under ADR, specified asset depreciation periods are used to compute depreciation for classes of assets covered by these rules. A taxpayer who elects this system is entitled to use depreciation periods which are within a range of 20 percent higher or lower than the regular ADR class lives. Special rules apply where assets under the ADR system are retired before the end of the depreciation period; for example, a loss from an ordinary retirement of an asset may not be deducted in the year the asset is retired.

In lieu of depreciation deductions which would otherwise be allowable, the owners of certain types of assets may elect to amortize these assets on a straight-line basis over a period which is usually substantially shorter than the actual useful life of the asset. This special treatment is available for certain pollution control equipment, which may be amortized over a 60-month period. If this election is made, only one-half of the regular investment tax credit is allowed.

Financial assistance for railroads

In the Railroad Revitalization and Regulatory Reform Act of 1976, Congress authorized $4.6 billion in aid to the rail freight industry over a five-year period. Title V of the Act makes available to all freight-carrying railroads (1) $1 billion in loan guarantees and (2) the purchase of $600 million in redeemable preference shares by the Federal Government, which is to be repaid within a 30-year period. A subsidized dividend rate may be granted and repayments may be deferred for up to 11 years. The Act also authorizes the purchase of $2.1 billion of bonds and preferred stock issue by Conrail.

B. House Bill

Business energy credits

1. In general

The House bill provides a business energy investment tax credit that is in addition to the regular investment tax credit. The credit is available at a rate of 10 percent for certain types of property, called energy property, during the period after April 19, 1977, and before January 1, 1983.

2. Energy property defined

In order to qualify as business energy property eligible for this special investment credit, the property must fall within one of the following five categories: (1) alternative energy property for which the credit against the oil and natural gas use tax has not been elected, (2) cogeneration property, (3) advanced technology property, (4) specially defined energy property, and (5) recycling equipment. These categories are explained in detail below.

To qualify as energy property, the property must be an integral part of, or used in connection with, a building or other structure located in the United States. Where the taxpayer is constructing the energy property, construction, reconstruction or erection must be completed after April 19, 1977. Similarly, property purchased by the taxpayer must be acquired after April 19, 1977, and its original use must be by the taxpayer and must begin after April 19, 1977. (As already noted, the credit is available only to the extent of costs incurred after this date and before January 1, 1983.) In addition, the property must be property for which depreciation or amortization is allowable and must have a useful life of three years or more.

For purposes of determining the eligibility of cogenerating property, advanced technology property and specially defined energy property for the energy investment credit, it is generally required that this property or equipment be used in connection with an existing building and, where applicable, an existing industrial or commercial process, as of April 20, 1977.

Except in the case of nuclear facilities, a building or facility will be considered to be existing if it has been substantially completed before April 20, 1977; that is, at least 50 percent of the taxpayer's basis in the building or facility must be attributable to construction, reconstruction, or erection which occurred before April 20, 1977. In the case of nuclear powerplants, the facility will be considered an existing building or facility if a construction permit was issued and construction had actually begun by April 19, 1977.

For all categories of energy property other than alternative energy property, this credit will be available only if the equipment meets performance and quality standards (relating to energy savings) prescribed by the Secretary (after consultation with the Secretary of Energy) which are in effect at the time the property is acquired or construction is begun.

If property qualifies as both alternative energy property or as one of the other categories of energy property, it will be treated as alternative energy property eligible either for the credit against the use tax or this business energy investment credit, at the election of the taxpayer.

3. Alternative energy property

Alternative energy property refers to property which is defined as such under the users tax rebate provisions, but with respect to which the credit against the business use tax has not been elected. The types of property which are included within the meaning of alternative energy property are boilers and burners, nuclear, hydroelectric and geothermal equipment, equipment to produce synthetic gas, pollution control equipment, and handling equipment to be used in conjunction with certain types of alternative energy property, as well as the plans and designs for alternative energy property. A detailed explanation of alternative energy property appears above in the explanation of the credit against the tax on the business use of oil and natural gas.

4. Cogeneration property

Under the House bill, cogeneration property means property which produces steam, heat, or some other form of useful energy (other than electricity) for industrial, commercial, or space heating purposes, and which also produces electricity. To qualify as energy property, cogeneration property must be installed in connection with an existing facility and must result in an expansion in the facility's cogenerating capacity (including the start of cogenerating activity).

In this context, cogeneration equipment includes the addition of equipment to produce or distribute steam, heat, or other energy from an existing electric generating facility and also the electrical generating equipment which is added to an existing boiler or other energy production or conversion system which produces steam or another form of energy other than electricity.

It is intended that cogeneration property include steam and heat distribution systems that are added to an existing electric generating facility. In addition, it covers an electric generating turbine which is added to an existing industrial or commercial boiler or other heat-producing source.

Where a taxpayer has an operational cogenerating capacity in place on April 20, 1977, the credit will be available only to the extent that additional or replacement cogeneration equipment increases the cogenerating capacity of the facility. For this purpose, the eligible investment is determined from either the incremental capacity (in terms of megawatts) to produce electricity or the incremental capacity to produce steam (in terms of pounds per hour) or other forms of heat.

5. *Advanced technology property*

Advanced technology property is defined as equipment which uses solar, geothermal or wind energy to provide heat, cooling or electricity in connection with an existing industrial or commercial building, and where applicable, an existing industrial process.

In the case of solar and wind energy equipment, the credit applies to such equipment (and parts solely related to the functioning of such equipment) which use solar and wind energy (either separately or to supplement each other) to provide heat, cooling, hot water or electricity. Generally, a solar energy equipment system involves the transformation of sunlight into heat or electricity through the use of such devices as solar cells or other collectors, storage systems for electricity and for hot air or hot water (including rock beds), heat exchangers to utilize captured and stored energy, and related equipment, such as fans and thermostats. The credit for wind equipment similarly applies to the windmill or other devices to harness outdoor moving air to provide electricity and other forms of energy and includes storage and transfer systems to distribute this energy.

The credit for geothermal equipment includes equipment, such as turbines and steam distribution systems, used in connection with a building or structure. Eligible property in this category does not include either (1) any type of equipment connected with a geothermal well or (2) stream distribution systems between a geothermal well and the point at which the stream enters the building, structure or other facility which utilizes the steam for application within the building or structure. While the credit does cover geothermal stream distribution systems within a building, it does not cover electrical distribution systems except for those which are integrally related to a geothermal steam powered generating turbine.

6. *Specially defined energy property*

This category of eligible property generally consists of equipment added to an existing building or process to conserve energy by recovering and further utilizing heat or unburned gases which would otherwise be wasted and which are contained in gases and fluids. Eligible property includes:

(1) recuperators;
(2) heat wheels;
(3) regenerators;
(4) heat exchangers;
(5) waste heat boilers;
(6) heat pipes;
(7) automatic energy control systems;
(8) turbulators;
(9) preheaters;
(10) combustible gas recovery systems; and
(11) economizers.

In addition to these types of property, the Secretary is authorized to specify other similar items of energy conservation equipment eligible for this credit.

7. *Additional equipment*

Additional eligible items of specially defined energy property include equipment added to existing industrial or commercial facilities which burn oil or natural gas, or use oil or natural gas as a feedstock,

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to modify these facilities to use coal, waste (such as biomass) or other combustible by-products as a fuel or feedstock in replacement of at least 25 percent of the oil or natural gas used before the modification. This credit will be available where the use of an alternate fuel or feedstock is at least 25 percent but not more than 50 percent. In the case of equipment that uses the mixture as a fuel (but not as a feedstock), this equipment will be treated as alternative energy property eligible either for the credit against the use tax or the energy tax credit, if the alternate fuel comprises more than 50 percent of the energy consumed. Qualifying investment in this category would include the costs of replacing or modifying existing combustors and burners to enable the facility to use this fuel mixture. Related pollution control equipment (such as scrubbers and electrostatic precipitators) and handling equipment would also qualify under this category if these two types of property satisfy the relevant requirements set forth in section 4998(b), concerning pollution control equipment and handling equipment which qualify as alternative energy property.

8. *Recycling equipment*

The final category of property which qualifies for the energy investment credit is equipment used to recycle solid waste. The credit here is limited to solid waste recycling equipment because equipment to recover and recycle waste heat and gases is included under the specially defined energy property category.

Equipment covered under this category must be used exclusively for one of two purposes, either to sort or otherwise prepare solid waste for recycling or to process (recycle) the solid waste materials. This would include, for example, equipment which separates recyclable solid waste from a mixture of waste materials. Equipment which functions exclusively to prepare solid waste materials would also be covered. For example, processes which apply a thermal, mechanical or chemical treatment to waste to condition or prime the materials so they will respond properly to the recycling process are included. Equipment in the actual recycling function is also included up to the point where a refined material has been created which can be used to the same extent as materials from one or other virgin substances to fabricate an end product.

9. *Rules of general application*

Several changes in the regular investment credit rules are made for purposes of applying the business energy investment credit. First, the business energy credit for alternative energy property may be offset against 100 percent of the taxpayer's income tax liability, rather than the generally applicable limitation of 50 percent of tax liability (in excess of $25,000). This increased limitation applies only to alternative energy property; it does not apply to the other categories of property eligible for the business energy credit. The 100 percent limitation also will be available for carrybacks and carryforwards of credits attributable to alternative energy property, including those carried to tax years before 1977 and after 1982.

A second change to the generally applicable investment credit rules involves the elimination of the lodging limitation (sec. 48(a)(3)) for purposes of the business energy credit. As a result, the business energy credit is available both for energy property installed in connection with a lodging facility which provides accommodations to transients (for which the regular investment credit may be claimed for qualifying property under present law) and for energy property installed in connection with facilities (such as apartment houses) which predominantly provide long-term accommodations (for which the regular investment credit is generally not available under present law).

A special rule is also provided for energy property that is partially or entirely financed by industrial development bonds, whose interest is exempt from Federal income tax under present law. In this situation, the business energy credit will be 5 percent, instead of the 10 percent rate which is generally available.

For the purposes of the business energy credits, the term industrial includes agricultural to reflect the committee's intent that energy property used in connection with an agricultural operation or process also will qualify for the energy investment credit.

Investment tax credit for business insulation property

Business insulation property which is a structural component of a building would be eligible for the regular investment tax credit, if placed in service during the period from April 20, 1977 through December 31, 1982. This provision of the House bill applies to business insulation property that presently is not eligible for the investment tax credit. The criteria that are employed ordinarily to determine whether property is eligible for the credit would apply to this property; for example, the property must have a useful life of at least 3 years, and partial credits are allowed for useful lives of 3 through 6 years.

Business insulation property is defined as property which is specifically and primarily designed to reduce the heat loss or gain of an existing commercial or industrial building or facility in or on which the insulation property is installed. In addition, such insulation must be new property, have a useful life of at least three years, and meet performance and quality standards prescribed in regulations by the Secretary of the Treasury after consultation with the Secretary of Energy. This regulatory authority is to be applied prospectively only, and thus, these standards will not apply to insulation property purchased prior to the promulgation of such standards.

Qualifying property includes not only insulation, but also a variety of other items designed to reduce heat loss or gain, including double glazing, reflective glass coatings, storm doors and windows, and weatherstripping.

Denial of investment tax credit and accelerated depreciation for certain property

Under the House bill, several tax incentives would be repealed for new investments in certain energy property. In particular, the House bill deletes air conditioning and space heating units (that is, those not considered structural components) from the definition of tangible personal property so that such property no longer will be eligible for the regular investment tax credit. Boilers or other combustors fueled by oil or natural gas also would be denied the regular (or any additional) investment tax credit, unless the use of coal or another alternate substance is precluded by existing Federal or State air pollution regulations, or unless the use of such a boiler or other combustor is an exempt use under the users tax provisions of the bill.

In addition, new oil or natural gas boilers would be required to use straight-line depreciation, rather than any accelerated depreciation method, and the useful life of such property must equal the class life prescribed by the Secretary without regard to the 20 percent variance in class life available under the ADR provisions of the Code.

Depreciation allowance for early retirement or replacement of oil or gas boilers

Special treatment is provided under the House bill for depreciation of a natural gas or oil-fueled boiler or other combustor which is retired or replaced with a non-oil or gas unit before the end of its originally determined useful life.

Under this provision, the taxpayer will be authorized to redetermine the useful life of an oil or natural gas fueled combustor and use this shortened useful life to depreciate the remaining basis in the property (net of any salvage value). If this treatment is elected, the taxpayer may use only the straight-line method for depreciation of the remaining basis. In order to qualify for this treatment, the taxpayer must establish to the satisfaction of the Secretary that there is a reasonable foundation for the conclusion that the combustor will in fact be retired or replaced at the end of the shortened useful life. The taxpayer will be eligible to use this treatment beginning with the taxable year in which the Secretary approves the application of the taxpayer to redetermine the useful life of the combustor under this provision.

If the taxpayer does not, however, retire or replace the boiler on or before the date established with the Secretary, he then is liable for the difference between the taxes he would otherwise have paid during the period and the taxes he actually paid. He must also pay interest, at a rate determined under section 6621, on the amount of the difference of such taxes.

C. Administration Position on the House Bill

The Administration generally supports the House-passed bill.

D. Other Congressional Consideration

1. Action in the 94th Congress

Insulation

Under H.R. 6860 and Title XX of the Tax Reform Act of 1976, the committee adopted a business insulation provision similar to that in the House version of H.R. 6860. Under this provision, the investment credit would have been made available for insulation installed after March 17, 1975, and before January 1, 1979, if the costs were paid (or accrued) between those dates. The insulation was required to be installed in a structure existing on March 17, 1975, and which was used on that date in a trade or business.

Qualified insulation included regular insulation and storm (or thermal) windows and doors, and similar items, such as weatherstripping or caulking, designed specifically and primarily to reduce the heat gain or loss of a building. The material installed had to be new property, have a useful life (to that taxpayer) of at least three years, and meet performance standards that were to be prescribed in Treasury regulations. Insulation in buildings which furnish permanent lodging, such as hotels and apartments, would also have qualified for the credit.

Solar energy equipment

The committee, in H.R. 6860 and in title XX of the Tax Reform Act of 1976, modified provisions in the House version of H.R. 6860 dealing with solar energy equipment. As amended by the committee, the investment credit was available for the costs (including installation) of solar energy equipment installed on business or commercial property after March 17, 1975, and before January 1, 1987. The amount of the credit was to be 20 percent of the cost of equipment paid for or accrued and put into use before 1982 and 10 percent of the cost of equipment placed in service after 1982 and before 1987. Exceptions from these time limitations were made in cases of certain binding contracts entered into within the applicable time limitation. The committee also deleted a provision in the House bill which would have allowed an election of rapid amortization instead of the credit.

To qualify for the credit, the taxpayer's cost for solar energy equipment was to have been paid or accrued before January 1, 1981. Also, the equipment had to be new in the hands of the taxpayer and had to have a useful life of at least three years. Unlike the investment credit for insulation, this credit would have been available not only for solar energy equipment installed in structures already in existence on March 17, 1975, but also for installations in new structures.

The investment credit under this provision would also have extended to solar energy equipment installed in business properties which furnish permanent lodging, such as apartments and hotels.

Solar energy equipment was defined as equipment which meets criteria established by the Secretary of Housing and Urban Development and which uses solar energy to heat or cool the building to which it is attached or to provide hot water for use within the building. The credit would not have been available, however, for back-up equipment which provides conventional heating or cooling during periods when the solar system is unable to function.

The committee also made available an additional 2 percent credit for taxpayers who established or maintained an employee stock ownership plan (ESOP) to which the employer contributes stock equal in value to 2 percent of the qualified investment in solar equipment. Similar 2 percent additional credits were also provided in connection with the other energy credits under the Senate provisions, including the geothermal credit, the wind-related equipment credit and the credit for qualified energy conversion and conservation equipment, all discussed below.

A Senate floor amendment to the Tax Reform Act of 1976 would have terminated the 20 percent credit after 1979, and would have terminated the 10 percent credit after 1981.

Geothermal equipment

The committee, in H.R. 6860 and in title XX of the Tax Reform Act of 1976, added a special investment credit for geothermal energy equipment installed on business or commercial property after December 31, 1976. The credit would have been available for equipment which became a structural component of a building and for equipment installed for business properties used predominantly to furnish lodging. The equipment eligible for the credit would have been that which uses geothermal energy to heat or cool a building or to heat water for it. Under a Senate floor amendment, the amount of the credit would have been 20 percent for equipment installed before 1980, and 10 percent for equipment installed in 1981 and 1982.

Wind-related energy equipment

The committee added, as a committee floor amendment to the Tax Reform Act which was later included in H.R. 6860, an amendment which would have extended the investment credit to wind-related energy equipment (such as windmills) installed for use in the trade or business of producing electricity or to generate electricity for use in a trade or business.

Under the amendment, the amount of the credit was to be 20 percent of the cost of the qualified wind-related energy equipment installed after December 31, 1976, and before January 1, 1980, and 10 percent for equipment installed in 1980 and 1981.

Denial of investment credit for portable air conditioners and heating units

The committee, in both title XX of the Tax Reform Act and H.R. 6860, adopted a provision in the House version of H.R. 6860 which would have denied the investment credit to portable and self-contained heating and air conditioning units, as is the case under present law for central heating and air conditioning units. This rule would have applied to all such units and would have been effective for such units placed in service after the date of enactment.

Denial of investment credit for petroleum powered electrical generators

The committee deleted a provision in the House version of H.R. 6860 which would have generally repealed the investment credit for electrical generating equipment which uses oil or other petroleum products (including natural gas) as its fuel and which would be placed in service after April 17, 1975.

Qualified energy conversion and conservation equipment

The committee amended provisions in the House version of H.R. 6860 which would have allowed rapid (5-year) amortization for capital expenditures to acquire or to construct, reconstruct or erect waste conversion equipment, shale oil conversion equipment, coal slurry pipelines, coal liquefaction and gasification equipment, and deep coal mining equipment. The committee, in H.R. 6860 and in title XX of the Tax Reform Act of 1976, instead made available 2 additional percentage points of investment credit for investment in qualified energy conversion and conservation equipment instead of rapid amortization. The additional credit was to be available for a 10-year period for all the equipment in this group except waste conversion equipment, for which the added credit was to be available for 5 years. A Senate floor amendment reduced the time during which the credit was available to 3 years for waste conversion equipment, deep mining coal equipment and shale oil conversion equipment and to 5 years for coal liquefaction and gasification equipment. The additional credit for coal slurry pipelines was deleted from the bill on the Senate floor.

Railroad provisions

As part of the Tax Reform Act of 1976, Congress provided that railroads were to be permitted to expense replacement ties (other than those made of wood). Under prior law, the railroads had generally been required to capitalize such costs and write them off only when the track was replaced or retired. That act also extended provisions permitting 50 year amortization of a railway grading and tunnel bores to property placed in service before 1969. Under prior law, 50 year amortization was available for grading and tunnel bores placed in service after 1968, and the cost of older tunnel bores and grading could be written off only if the property was retired or abandoned.

Congress also modified the investment credit limitations with respect to railroads, so that railroads are entitled to apply investment credits against 100 percent of their tax liability for 1977 and 1978. Beginning in 1979, this limitation will be phased down 10 percentage points a year through 1983 to reach the same 50 percent limitation which applies to most other taxpayers.

In addition to the measures outlined above, Congress considered, but did not enact, provisions for the rapid amortization of railroad rolling stock. Under the tax law, railroad freight cars and locomotives placed in service after 1968 and before 1976 could, at the election of the taxpayer, be amortized on a straight line basis over 60 months. This provision was enacted for a 5-year period in the Tax Reform Act of 1969 and was extended in 1974 for one more year, through December 31, 1975. The investment credit was not allowed on property for which the 5-year amortization provisions had been elected.

In its energy deliberations, the committee modified the House version of H.R. 6860, which would have allowed a 5-year amortization period and a two-thirds investment credit for qualified railroad equipment placed in service after 1974 and before 1980. Qualified equipment included railroad rolling stock, classification yards, communications equipment, freight handling equipment, railroad ferries and leased unit coal trains.

The committee, in H.R. 6860 and in the Tax Reform Act, instead adopted a provision which substituted a 12-percent investment credit for the railroad property incentives provided in the House bill. Railroad ferries were not eligible for the credit.

Recycling credit

The committee, in title XX of the Tax Reform Act of 1976, provided a tax credit to a recycler for purchases of recyclable solid waste material. The credit would have been available for qualified recycling purchases that exceeded 75 percent of a base period level.

Recyclable solid waste materials were defined as materials which must have been used by an ultimate consumer and have no significant value or utility except as waste. The ultimate consumer may be a household that discards newspapers, boxes, soda pop, and beer containers made from glass, plastic, aluminum, and other metals, and worn-out clothing. Scrap paper, boxes, and all other containers discarded as waste from residential, office, and commercial buildings also qualified. Discarded containers from industrial plants also were wastes that had been used by an ultimate consumer.

The full Senate substituted and passed (as an amendment to a bill later enacted) a requirement for a six-month study of the need for recycling incentives to be prepared jointly by Treasury and the EPA.

Rapid amortization for pollution control equipment

In the Tax Reform Act of 1969, five-year amortizations was initially made available to a taxpayer at his election for pollution control equipment that was placed in service after 1968 in a plant or other property that was in existence before 1969. The election, after an extension, was available for equipment placed in service before January 1, 1976, at which time the provision expired. The provision was enacted as a special incentive for the installation of pollution control equipment in the Tax Reform Act of 1969, because that Act repealed the investment tax credit.

In the Tax Reform Act of 1976, the Congress restored five-year amortization for pollution control facilities as a permanent provision. The provision applies to a new identifiable, certified pollution control facility installed in a plant in operation before January 1, 1976. The Act amended the prior law definition, which limited the provision to equipment that controls the emission of pollutants, to include equipment that prevents the creation of pollutants. The provision was limited to equipment that would not significantly alter the costs of production or the level of output. In the Statement of Managers accompanying the conference report, significantly was defined to mean a change greater than 5 percent. In addition, the Act provided that a facility or equipment for which the taxpayer elects five-year amortization will be eligible for a one-half investment tax credit. The limited investment credit will not be allowed, however, if the useful life of the facility or equipment would be less than 5 years.

Restoration of the election for five-year amortization was effective with respect to certified pollution control equipment placed in service after December 31, 1975. The investment credit is generally available for such equipment placed in service after December 31, 1976.

2. *Senate action in the 95th Congress*

On September 7, the Senate approved an amendment to the Natural Gas and Petroleum Conservation and Coal Utilization Policy Act (S. 977) that increased the assistance to rail freight carrying companies provided under the Railroad Revitalization and Regulatory Reform Act from $600 million to $700 million. The additional $100 million is to be used to facilitate rail transportation of coal and coal products to regions or States which can use coal in greater quantity.

E. Areas for Committee Consideration

There are two main purposes served by the energy tax credit provisions in the House bill. First, the bill provides investment tax credit incentives to encourage the use of coal, solar, geothermal, wind and other energy sources rather than oil or natural gas. This energy conversion goal is also reflected in the provisions which generally deny investment tax credits and accelerated depreciation to new oil and natural gas burning facilities and allow accelerated depreciation where an existing facility of this type will be replaced by a non-oil or gas burning facility in the near future. The second goal which is intended to be achieved by these provisions in the House bill is conservation in the use of energy resources. This goal is promoted by extending the energy investment credit to cogenerating and recycling equipment and to a variety of industrial and commercial heat and gas recovery devices. The regular investment credit is correspondingly extended to insulation for business property and the investment credit is denied for energy-inefficient portable air conditioners and heaters.

There are a number of policy issues and technical questions which the committee may wish to consider during its deliberations on this part of the House bill.

Policy issues

1. Incentives for new facilities or expanded capacity

Under the House bill, the energy tax credit is available for alternative energy property and recycling equipment installed in connection with a totally new facility, as well as an existing facility, while this credit is not generally available to the other categories of otherwise qualifying property unless the property is installed in connection with an existing structure or industrial process. The committee may wish to consider whether the existence of the business use tax is a sufficient disincentive for the use of oil or natural gas in connection with new facilities and whether the energy investment credit incentive should as a result be made available only for the various types of energy property installed in existing facilities which presently use oil or natural gas.

A similar question involves existing facilities where new qualifying property that replaces existing oil or natural gas equipment provides a higher energy output than the equipment which is replaced. The committee may wish to consider limiting the availability of the energy credit to the extent of the replacement of capacity and deny the credit for the incremental energy capacity.

2. New property limitation

The House bill also limits the credit to *new* qualifying property. The committee may wish to consider making the credit available for a limited amount of used qualifying property each year, similar to the treatment of used property under the regular investment credit rules.

3. Cogeneration equipment

The House bill makes the energy investment credit available to equipment which is added to an existing facility to enable the facility to cogenerate, that is both generate electricity and produce another form of useful energy. In this connection, it is possible that an oil or natural gas boiler could be added to enable a facility to cogenerate and that this boiler would qualify for the credit. Since the use of oil and gas boilers is not generally compatible with the goals of this bill, the committee may wish to consider modifying the House bill to insure that both the regular and this special investment credit are denied where a non-exempted oil or gas boiler is installed in circumstances which would otherwise enable such installation to qualify for the energy investment credit.

4. Recycling equipment

The committee may wish to consider two modifications in the descriptions of recycling equipment that would qualify for the business energy tax credit.

First, the House bill provides that eligible recycling property must be used exclusively for recycling purposes. The equipment used to process recyclable materials into new products frequently can be used with virgin or recyclable materials. Because the House wanted to reduce energy consumption by encouraging the re-use of discarded materials instead of the use of virgin materials, it required that the qualified equipment be used exclusively for recycling, even when the equipment could be used with virgln material as well as recyclable material.

In some recycling processes, however, small amounts of virgin materials are used with recyclable materials as so-called stabilization agents. The stabilizing virgin materials in such situations constitute about 3 to 5 percent of the total amount of materials processed during recycling. Another version of the same situation arises where the equipment is used primarily for recycling, but some production runs are made with virgin materials. The committee could consider making a minimal allowance for the use of virgin materials that would cover both types of situations described above while still essentially restricting the credit to equipment used in recycling.

The House bill limits the availability of the recycling credit to equipment that results in an increase in the taxpayer's recycling capacity. This provision would deny recycling firms the use of the credit when it becomes necessary to replace equipment that has become technologically obsolete or has outlined its useful life and has been fully depreciated.

Technical questions

1. Coordination of property eligible for the energy credit with qualifying property eligible for the bussiness use tax credit

The House bill contains two provisions for tax incentives for boilers which use a mixture of oil and a fuel other than oil or natural gas. Under alternative energy property, a partial use tax rebate or investment credit is given for equipment to modify an existing boiler in an existing electric generating facility. Under a separate provision the energy investment credit is also given for similar modification equipment except that this provision includes existing feedstock uses and existing nonboiler combustors. There is also a provision which states that any property which is defined as alternative energy property is not included in this second category of modification equipment.

The existence of two separate provisions introduces additional complexity to the bill, and since the two provisions deal with basically the same type of property, the committee may want to consider broadening the definition of alternative energy property to include these two provisions that are covered under the energy investment credit and delete the reference to them in the energy investment credit.

The same problem of overlapping provisions arises for property which uses geothermal energy. Certain equipment used in the production of energy by geothermal power qualifies as alternative energy property eligible for either the user tax credit or the energy investment credit, including such equipment installed in connection with a new facility. Under a separate provision, property eligible for the energy investment credit includes equipment which uses geothermal energy to provide heat, cooling, or electricity in connection with an existing facility. The committee may wish to combine these two provisions.

2. Increased investment credit limitation for alternative energy property

The House bill increases the generally applicable 50 percent of tax liability limitation to 100 percent for investment credits generated by alternative energy property. It should be made clear that this increased limitation applies only for credits earned by such property under the special energy investment credit and not the regular investment credit.

Ordering rules should also be provided to deal with situations where a taxpayer may have available in the same tax year energy and regular investment credits subject to both the 100 percent and 50 percent limits. The committee may wish to specify that the credits subject to the 50 percent limitation are to be applied first and then credits subject to the 100 percent limitation are applied. Carrybacks and carryovers of these credits should also retain their character.

3. Specially defined energy property

The language of the House bill limits eligibility of this category of property for energy investment credits to property installed in connection with existing industrial or commercial processes and facilities. It should be made clear that this category extends to property installed in connection with existing industrial or commercial buildings, such as office buildings.

The rules under this provision specify eleven items of qualifying property and authorize the Secretary of the Treasury to specify other qualifying items. Corresponding authority should be given to the Secretary to delete items from this list on a prospective basis subject to criteria prescribed by the committee.

4. Coordination with reclassification procedure

The House bill provides generally for a denial of the regular investment credit and accelerated depreciation methods for oil and gas-fired boilers. However, there is an exception to this rule which provides that in most instances where a particular use is exempt from the users tax under the bill, it will also be entitled to receive the investment credit and normal depreciation methods. Due to a technical oversight, this rule did not apply where a particular use received a permanent exemption from the tax under the reclassification procedure. The committee may wish to provide that where a permanent exemption is granted under that procedure, the regular investment credit and normal depreciation methods will also be available for the boilers pursuant to the exemption.

V. REVENUE EFFECTS

The revenue effects under the House bill of the tax on the business use of oil and natural gas, the credits against that tax, and the business energy tax credits are shown in the following tables.

Excise tax on business use[1] of oil and natural gas under title II of H.R. 8444, as passed by the House: Relationship of gross tax to net effect on budget receipts, fiscal years, 1979–85

[In millions of dollars]

	1979	1980	1981	1982	1983	1984	1985	Total, 1979–85
Gross tax before rebate for qualified investment		1, 734	2, 796	3, 642	4, 678	5, 605	6, 638	25, 093
Rebate for qualified investment		−1, 298	−2, 686	−3, 421	−3, 990	−4, 780	−5, 714	−21, 889
Reduction in income tax liabilities of businesses resulting from less than full passthrough of tax to prices	−25	−38	−22	−57	−96	−110	−140	−488
Net effect on budget receipts	−25	398	88	164	592	715	784	2, 716

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[1] Other than utility.

Business energy conservation, and advanced technology tax credits under title II of H.R. 8444, as passed by the House, fiscal years 1978–85

[In millions of dollars]

Credit provision	1978	1979	1980	1981	1982	1983	1984	1985	Total, 1978–85
Credit for nonrebate alternative energy property	−23	−21	−32	−50	−58	−34			−218
Credit for cogeneration property [1]	−28	−41	−80	−127	−159	−91			−526
Credit for advanced technology property (solar, geothermal, and wind-related equipment) [1]	−15	−19	−26	−42	−58	−37			−197
Credit for specially defined energy property (primarily heat recovery equipment; also includes mixed fuel burning equipment) [1]	−224	−218	−250	−306	−350	−225			−1, 573
Credit for recycling equipment	−29	−28	−30	−34	−37	−21			−179
Credit for business insulation property [1]	−90	−88	−98	−114	−127	−83			−600
Total	−409	−415	−516	−673	−789	−491			−3, 293

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[1] Only if applied to or within a structure in existence before Apr. 20, 1977.

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